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ABSTRACT

This study surveys the existing literature related to various technical aspects of electric power production, with primary emphasis on the supply of the various fuels used in the production of electricity and on the environmental consequences of energy conversion. It was prepared by the Environmental Policy Division, Legislative Reference Service, Library of Congress, at the request of the Congressional Joint Economic Committee for use as background material in the Committee's investigation of the economic aspects of electric power production. A wide range of issues are identified and discussed, issues classified as operational, economic, technological, environmental, resource, and regulatory. Statistical data and legislative references frequently supplement the narrative material. (BL)

91st Congress
2d Session } JOINT COMMITTEE PRINT

THE ECONOMY, ENERGY, AND THE ENVIRONMENT

A BACKGROUND STUDY

PREPARED FOR THE USE OF THE

JOINT ECONOMIC COMMITTEE
CONGRESS OF THE UNITED STATES

BY THE ENVIRONMENTAL POLICY DIVISION
LEGISLATIVE REFERENCE SERVICE
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SEPTEMBER 1, 1970

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LETTERS OF TRANSMITTAL

SEPTEMBER 1, 1970.

To the members of the Joint Economic Committee:

Transmitted herewith for your use is a background study prepared at the committee's request by the Legislative Reference Service of the Library of Congress, entitled "The Economy, Energy, and the Environment." This study surveys the existing literature relating to various technical aspects of electric power production, with primary emphasis on the supply of the various fuels used in the production of electricity and on the environmental consequences of energy conversion.

The committee requested this study in order that the members might have needed background material conveniently available as we undertake our investigation of the economic aspects of electrical power production. As we proceed in our study, I anticipate that, with the assistance of the committee staff and of such experts as we may call to testify, we will be examining such aspects of energy production as pricing and advertising policies, regulatory policy, credit requirements, research needs, and means of achieving adequate electrical supplies in a manner consistent with preservation of our natural environment.

The study transmitted herewith was not designed to cover all of these economic questions in depth, but to provide the background information on which to build our further study. On behalf of the committee, I express our appreciation for the fine service rendered by the Environmental Policy Division of the Legislative Reference Service in preparing this study.

Opinions or conclusions expressed in this study should not be taken necessarily to represent the views of members of the Joint Economic Committee or of the committee staff.

Sincerely,

WRIGHT PATMAN,
Chairman, Joint Economic Committee.

THE LIBRARY OF CONGRESS,
LEGISLATIVE REFERENCE SERVICE,
Washington, D.C., August 31, 1970.

Hon. WRIGHT PATMAN,
Chairman, Joint Economic Committee,
U.S. House of Representatives, Washington, D.C.

DEAR MR. CHAIRMAN: I am pleased to transmit herewith a report "The Economy, Energy, and the Environment" prepared at your request in our Environmental Policy Division under the direction of Mr. Richard A. Carpenter, Chief. As you suggested, we have surveyed the major recent literature concerning the growth and composition of energy conversion and its environmental impact, with primary

emphasis on electricity generation and the fuels for this industry. The sections on electricity were written by Dr. Warren H. Donnelly, specialist in the Science Policy Research Division. The review of fuels availability was prepared by Dr. John K. Rose, senior specialist in natural resources and conservation.

Sincerely,

LESTER S. JAYSON,
Director, Legislative Reference Service.

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AN OVERVIEW

ENERGY

Our civilization and economy differ from those of early times in one vital characteristic, which is the enormous use of energy by our people throughout their lives.

Energy is the ability to do work. Power is the rate of doing work. For centuries the only sources of energy were the muscles of man and beast, supplemented slightly by energy that could be tapped from moving winds and waters. With the invention of the steam engine and the coming of the industrial revolution, modern man began to use large amounts of energy derived from burning fuels, and the power output of his machines increased.

A full-grown man is capable of an average power output of about 1/20th of a horsepower during an 8-hour working day, equivalent to an output of about 37 watts of electrical energy. Thus, when a child turns on a 150-watt television receiver, he commands electrical energy equivalent to the energy output of four grown men. As long as human progress depended mostly on the energy of human muscles, there could not be much physical change in the conditions of primitive life.

Today human labor provides energy for far less than 1 percent of the work performed in factories, refineries, and mills in the production of their products. Literally, our economy and our way of life could not continue without use of vast amounts of energy.

One measure of this situation is the increase in the total power for all engines, turbines, and work animals over the past 3 decades. Table 1 shows the increase from 2.7 billion horsepower available in the United States in 1940 to 17.9 billion for 1968. Of this, engines in trucks, buses, and automobiles accounted for by far the largest part, increasing from 2.5 billion horsepower in 1940 to 16.9 billion horsepower in 1968. Over the same period, the power of electric generating stations increased from 53 million horsepower to 371 million horsepower.

TABLE 1.—TOTAL HORSEPOWER OF ALL PRIME MOVERS: 1940–68

[In thousands. As of January, except as noted. Prior to 1960, excludes Alaska and Hawaii, except as noted. Prime movers are mechanical engines and turbines, and work animals, which originally convert fuels or force (as wind or falling water) into work and power. Electric motors, which obtain their power from prime movers, are excluded to avoid duplication. See also Historical Statistics Colonial Times to 1957, series S 1–14]

Item	1940	1950	1955	1960	1965	1968 (preliminary)
Total horsepower	2,773,316	4,867,538	7,158,229	11,007,889	15,096,332	17,912,944
Work animals	12,510	7,040	4,141	2,790	2,000	1,460
Inanimate	2,760,806	4,860,498	7,154,088	11,005,099	15,094,332	17,910,684
Automotive [1] [2]	2,511,312	4,403,617	6,632,121	10,366,880	14,306,300	16,937,725
Nonautomotive	249,494	456,881	521,967	638,219	788,032	972,959
Factories	21,768	32,921	35,579	42,000	48,400	52,000
Mines	7,332	22,000	30,768	34,700	40,300	43,400
Railroads [3]	92,361	110,969	60,304	46,856	43,838	57,607
Merchant ships, powered	[4] 9,408	[4] 23,423	[4] 24,155	23,890	24,015	20,413
Sailing vessels	[4] 26	[4] 11	[4] 5	2	2	1
Farms	57,472	157,533	207,742	237,020	269,822	290,600
Windmills	130	59	59	44	30	24
Electrical central stations [2]	53,542	87,965	137,576	217,173	307,025	371,756
Aircraft [3] [5]	[4] 7,455	[4] 22,000	[6] 25,779	36,534	54,600	137,158

[1] Includes passenger cars, trucks, buses, and motorcycles.
[2] As of July 1.
[3] Beginning 1965, not strictly comparable with earlier years.
[4] Includes Alaska and Hawaii.
[5] Includes private planes and commerical airliners.

Source: Statistical Abstract of the United States, 1969, p. 509.

Another way of looking at use of energy is to ask who is using it. Table 2 and figure 1 show the consumption of energy resources by major consumer for the years 1963, 1965, and 1967. The use of energy is rather evenly divided between household and commercial use, industrial use, transportation, and generation of electricity. Industrial use accounts for almost one-third of the total. The British thermal unit is the standard unit for measuring heat energy and represents the amount of heat that will increase the temperature of 1 pound of water by 1° degree Farenheit.

TABLE 2.—CONSUMPTION OF ENERGY RESOURCES, BY MAJOR CONSUMER GROUP: 1963, 1965, AND 1967

[In trillions of British thermal units, except percent]

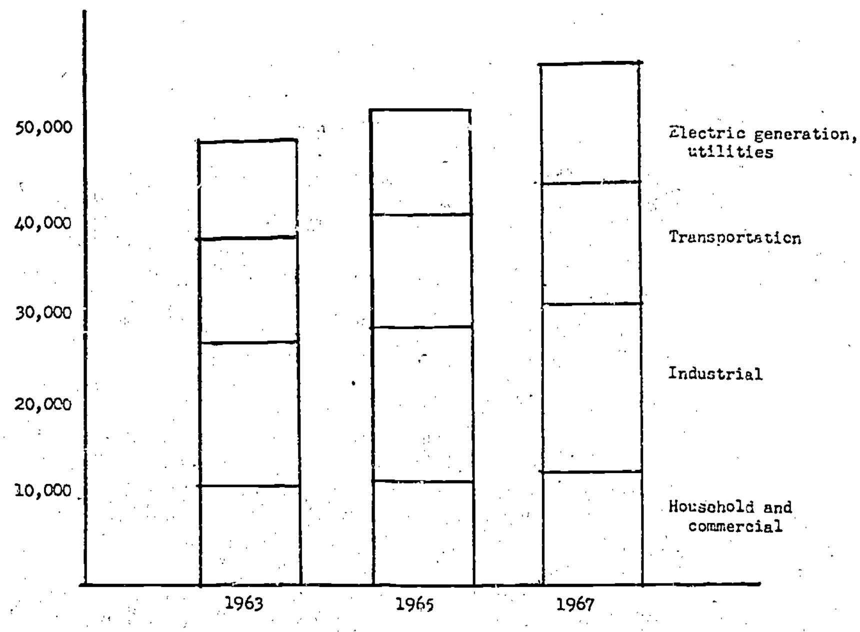
Consumer group	Energy inputs			Percent distribution		
	1963	1965	1967 (prel.)	1963	1965	1967 (prel.)
Total	49,649	53,785	58,853	100.0	100.0	100.9
Household and commercial	11,059	11,867	13,025	22.3	23.1	22.1
Industrial	16,225	17,550	18,634	32.7	32.6	31.7
Transportation [1]	11,964	12,715	14,021	24.1	23.6	23.8
Electrical generation, utilities [2] [3]	9,663	11,104	12,875	19.5	20.6	21.9
Miscellaneous	738	549	298	1.5	1.0	0.5
Utility electricity purchased [3]	3,128	3,600	4,134	(4)	(4)	(4)

[1] Includes bunkers and military transportation.
[2] Represents outputs of hydropower and nuclear power converted to theoretical energy imputs at prevailing rate of pounds of coal per kilowatt-hour at central electric stations using 12,000 Btu per pound coal. Excludes imputs for power generated by nonutility plants which are included within the other consuming sectors.
[3] Electricity generated and imported.
[4] Not applicable.

Source: Statistical abstract of the United States, 1969, p. 510.

FIGURE 1

Consumption of energy resources by major consumer group, 1963, 1965, and 1967



The growth in use of energy in the United States is dynamic and is outpacing the growth in population. If the past is any indication of the future, new energy sources will crowd into the energy marketplace before existing sources are depleted. During the 1860's, about 75 percent of the Nation's inanimate energy supply came from wood. By 1900, wood supplied only 21 percent of the energy with coal, dominant with 71 percent of the energy market. By the later 1930's, oil and gas were challenging the position of coal and shortly after World War II were supplying more energy than coal.

The years following World War II saw another shift as the use of natural gas grew faster than crude oil. In 1968, natural gas production, including liquids made from natural gas, supplied 34.7 percent of the Nation's energy. Domestic crude oil supplied 35.3 percent, including oil imports raises the oil's share to 40.1 percent. The higher rate of gas consumption combined with increase demands for protection of the quality of the environment, logically could result in natural gas becoming the Nation's largest energy source within a few years if adqeuate supplies are available. However, there is present doubt about the adequacy of natural gas supply.

As for present use of energy, according to a recent report of the Bureau of Mines,[1] the energy consumption of the United States in 1969 was the highest ever.

[1] U.S. Department of the Interior, Bureau of Mines, "Nation's Energy Consumption at Record High." News release, Apr. 6, 1970.

Energy equivalent to 65,645 trillion British thermal units was required to meet the Nation's total 1969 requirements for heat, light, and all forms of power. This represents a 5.1-percent increase over 1968 consumption, slightly below the previous year's growth rate.

The record energy demand was met principally through increased use of natural gas and petroleum, plus slight increases in the use of coal, hydropower, and nuclear power.

Compared with 10 years ago, 1969 energy consumption represents a 51.2-percent increase at an average growth rate of 4.2 percent annually over the past decade. Over that 10-year period, the Bureau noted, consumption of dry natural gas grew 75.4 percent; water power, 55.8 percent; petroleum and natural gas liquids, 44.4 percent; and bituminous coal and lignite, 37.7 percent. Anthracite consumption declined 49.8 percent. Nuclear energy, whose use in generating electric power was negligible 10 years ago, jumped to 141 trillion Btu.

In terms of consumption, the largest energy increase of 1969 was in electric utility power (12.1 percent), followed by energy for household and commercial needs (6.9 percent), industrial uses (5.2 percent), and transportation (4 percent).

Petroleum, continuing as the dominant fuel, supplied 43.2 percent of all U.S. energy demands in 1969. The other energy sources, and each one's share in meeting the year's total energy needs were natural gas (excluding natural gas liquids), 32.1 percent; bituminous coal and lignite, 20.1 percent; waterpower, 4 percent; anthracite, 0.4 percent; and nuclear energy, 0.2 percent.

Coal was still the major fuel for generating electric power in 1969, but its share of the electric utility market declined from 61.7 percent in 1968 to 57.5 percent last year. Electric utilities accounted for 61 percent of total coal consumption.

Domestic demand for petroleum and natural gas liquids increased 5.1 percent to 5,152 million barrels; dry natural gas demand was up 7.5 percent to 20,385 billion cubic feet; and demand for bituminous coal rose 1.1 percent to 505 million tons.

Domestic crude oil production was up only 1 percent last year, compared to 3.5 percent in 1968. Imports accounted for most of the increase in oil consumption.

Natural gas gained in all its consumer sectors, particularly in electric power generation by utilities.

Given a dynamic, changing pattern in energy demand and supply, one can understand the different opinions about the future of the U.S. energy market shown by various forecasters. Although nuclear power supplies only a minute part of present energy demands, some forecasters expect uranium and thorium will become the largest single source of energy for the Nation within the next three decades. However, given our larger resources of coal and oil shale, and the technological prospects for converting them into fluid fuels, the dominance of the petroleum like fuels is thought likely to continue for the rest of this century. For the more distant future, there are hopes that certain forms of hydrogen atoms, which are present in nature, can be used as fuel in the fusion process, which in essence could provide an inexhaustible supply.

As for the future, the Office of Science and Technology recently released the results of a study made for it by the Battelle Memorial Institute which compared many recent forecasts of energy supply

and demand. According to this report,[1] energy consumption in the year 2000, including nonfuel uses, is expected to be about 170,000 trillion British thermal units if real gross national product grows at about 4 percent per year. Consumption in 1968 was slightly over 62,000 trillion B.t.u. The average annual indicated growth rate is about 3.2 percent.

Although a figure of 170,000 trillion B.t.u. in the year 2000 appears reasonable to the Institute, on the basis of extrapolating current trends, it does not reflect the effect of new factors which are already emerging. Most important of these is the growing concern for protecting the environment. Also this figure may not adequately reflect possible changes in efficiency of energy conversion and changes in the pattern of energy use, especially the larger share expected to go into electric power production.

All of the existing projections analyzed by the Institute estimate that oil (including natural gas liquids) will continue to be the Nation's largest source of energy through the year 2000. Natural gas, excluding liquid fuels made from natural gas, is expected to continue to be the second largest source of energy. Of three projections for both nuclear power and coal at the end of the century, one estimates that coal will provide slightly more energy than nuclear, another estimates just the opposite, and one foresees a large margin for nuclear. At the moment the Federal Power Commission and the Atomic Energy Commission favor the second estimate.

Hydroelectric power is expected to continue to grow but to be of decreasing relative importance and to supply the smallest amount of any of the commercial energy sources in the year 2000. Nuclear generation is expected to exceed hydroelectric generation some time between the years 1975–80.

A consistent rate of growth of energy consumption toward the expected figure of 170,000 trillion B.t.u. for the year 2000 would require 3.4 quintillion (3.4×10^{18}) B.t.u. in the 32 years from 1968 to 2000. This is equivalent to the energy in 590 billion barrels of crude oil or 170 billion tons of average grade U.S. coal resources, assuming 20 million B.t.u. per ton.

Relative to past consumption, expected consumption in the 32 years 1968 to 2000 will be almost three (2.8) times that at the prior 32 years, 1936 to 1968. Providing fuel to generate such quantities of energy will pose a substantial problem for the energy industries and for Government policy, since the Nation has been consuming its higher grade, more accessible resources first and since even the much smaller energy consumption of the last three decades has already created serious environmental problems.

ENERGY AND THE SOCIETY AND ECONOMY OF THE UNITED STATES

The economy of the United States and the technologically advanced nations is based on energy. Energy is the ultimate raw material which permits the continued recycle of resources into most of man's requirements for food, clothing, and shelter. The productivity (and consumption) of society is directly related to the per capita energy available.

[1] Executive Office of the President, Office of Science and Technology, "A Survey and Comparison of Selected United States Energy Forecasts." Prepared for the * * * by the Pacific Northwest Laboratories of Battelle Memorial Institute, December 1969, 79 pages.

Population growth and an increased standard of living through technological activity have spurred a steady expansion of energy consumption. The extraction, transportation, and preparation of fuels; the manufacture of energy conversion machinery; the production of electric power; and the management of waste products and waste heat are industrial activities which have grown exponentially in the past few decades.

Predictions of future levels for the economy and energy are beginning to reveal limits imposed by environmental factors. The recognition of finite abilities for the air and water, and landscape to yield fuels and assimilate wastes poses a direct challenge to growth. Ecological information suggests the possibility of irreversible changes in the environment through energy exploitation. Decisions are necessary in the near future in order to preserve options for the long term survival of society.

It is clear that the environment cannot support unlimited growth of energy conversion because all energy eventually is discharged in the form of heat. Local thermal effects around major cities are already noticeable. However, by clever application of scientific knowledge and prudent allocation of energy resources, a high standard of living can be obtained for a rather large world population.

Within this global limitation imposed by the interactions of the economy, energy, population, and the environment, lie several subsets. Some energy resources will be exhausted in the near future. Certain geographical locations may be at an economic disadvantage because of high fuel costs while other areas may be saturated as to their abilities to absorb wastes. Shifts from one fuel to another will occur.

The current high level of concern for environmental quality is dramatizing the basic conflicts among alternative uses for natural resources. Choices must be made which will preserve the long-term health of the renewable environment (air, water, and living systems), yet will allow the prudent exploitation of fuels and minerals. The concept of recycling materials is growing in importance and will provide the ultimate answer to many of the mineral supply questions.

However, fuels are degraded permanently as they are used—ending up in the form of thermal energy which is radiated from the earth into space. To this extent the fuel supply of the planet is always finite and decreasing. The constant supply of incoming solar energy is very large in comparison to fossil or nuclear fuels but it is difficult to concentrate for industrial purposes and is not considered a significant capturable source for a high technology society.

Conventional economics emphasizes the short-term, localized gain as opposed to the long-term, worldwide balance of cost and benefit. In addition, the newly appreciated values of affluent nations are not easily quantified or expressed in monetary units. Thus the market place as a decisionmaking institution may fail to produce the best choices.

In seeking the long-term optimum for worldwide development, technological and economic forecasting are essential tools for the decisionmaker. Forecasts are based on extrapolations of past and present trends, new possibilities through applied science, population growth rates, anticipated changes in human activity, and so forth.

Inspection of past forecasts for energy consumption in the light of present facts shows that they have quite often been too conservative. However, limitations from environmental factors may make current forecasts turn out to be too expansive.

Another aid to management judgment is the calculation of reserves of fuel—oil, gas, coal, hydropower, uranium, thorium, etc. A lesser degree of uncertainty accompanies these statistics since they have been developed for many years and the exploration of the earth's surface is well advanced. Nevertheless, the economics of extraction, preparation, and transportation has been complicated by environmental considerations such as oil spills from tankers and the removal of sulfur from coal and oil. While the supplies of fuel in terms of heating value alone may be calculated fairly accurately, the availability of fuels suitable for specific applications or geographical areas can be altered radically and quickly in the name of pollution abatement.

Thus, reliable information for decisionmaking is badly needed in the energy based economy at a time when precision is threatened by many new factors—foremost among them being environmental quality. This report analyzes the recent literature pertinent to energy—particularly electricity, the economy and the environment. A summary of existing knowledge is presented as a backdrop for possible congressional hearings which would elucidate the difficult conflicts to be resolved and point the way for government and private sector organizations to obtain additional data.

THE SITUATION FOR ELECTRICAL ENERGY

As the Nation enters the remaining third of the 20th century, electricity literally has become a necessity for urban, suburban, and rural life, in both its economic and social aspects. At present most of the electricity is generated and delivered by electric utilities, and the decisions affecting the future supply of electricity in large part will be those of the management of those utilities.

Three interacting questions about electricity arise for the remaining three decades of the 1900's. These are:

(1) Is there a gap, now or later, between demand and supply for electricity?

(2) What are the environmental effects of the electricity industry, what can be done about undesirable effects, and what are likely to be the costs of control or abatement of these effects?

(3) What will environmental quality protection regulations do to alter the choice among fuels for electricity generation?

A review of current thought about these three questions suggests the following summary answers:

Concerning an electricity gap, some responsible officials and utility officers expect there will be occasional shortages of electricity again this summer. The results of the shortage may be a decrease in the quality of electrical service by lowering the voltage, or, in more severe instances, the temporary cutting off, or shedding, of some users to keep the total electrical demand of a system within its ability to supply. As for the longer term outlook, the industry and Government expect that powerplants can be built to supply future requirements, but only if a series of assumptions turn out favorably.

Concerning the environmental effects of generating electricity and carrying it to its users, the wastes from very large powerplants are certain to cause definite and probably unacceptable environmental effects unless equipment and procedures are used to control and abate discharge of wastes to the air and water. The added capital investment for waste control facilities, their costs of operation and their possible adverse effect upon operating efficiency of powerplants all can be expected to increase the cost of generating electricity, which ultimately must be reflected in an increase in the price paid by the user. How much this increase will be is conjectural. It seems likely to be acceptable for residential users, except that the effect will bear most heavily upon the poor. However the increase may change the economics of certain industries that use large amounts of electricity, such as metal refining and processing.

Unless methods are developed to permit the use of fossil fuels of high natural sulfur content, present trends in public insistence upon use of low sulfur fuels can lead to a rapid use of our natural gas reserve, a growing reliance of parts of our country upon imported fuels and a diminished use of coal even though this is the most plentiful of the fossil fuels. Furthermore, expectations that the supply of electricity will be adequate to meet future demand also assumes a major technological step forward in nuclear power—use of the breeder reactor—will be commercially attractive and feasible by the 1980's.

Some perspectives

The Federal Power Commission expects that by the year 1990 the Nation's electricity industry will have to plan, finance, build and bring into operation nearly 900 million kilowatts of new electrical generating capacity, almost three times that available in 1970. In addition, the industry must also replace existing powerplants as they become too obsolete to continue in use. Over recent years, utilities have retired old steam generating plants at an average rate in excess of 0.6 million kilowatts per year.

This expansion will require the utilities to find some 225 new sites for very large new steam electric plants for individual units of 500 megawatt output or larger. Of these 91 are expected to be for fossil fuels and 164 for nuclear power. The expansion of generating plants and transmission lines will require the industry, in its privately, publicly, and cooperatively owned segments, to raise an estimated $350 billion during the next two decades. The combined output of the new steam-electric plants approximates 450 times that of the largest steam electric plants currently in operation in the United States, or of 670 new Hoover Dams.

To supply the utilities with fossil and nuclear fuels for future generation of electricity will also demand a marked expansion in the supply of coal, oil, gas, and uranium. Complicating factors are:

(1) Regulations that limit the sulfur content of fossil fuels.

(2) Opposition to the import of low sulfur fuels.

(3) The possibility that new discoveries of natural gas will not keep pace with expanding use for generation of electricity.

(4) The technical and economic practicability of the breeder reactor remains to be demonstrated.

To transmit the electricity generated at these plants to the using areas within and between the States will require obtaining rights-of-way for and building an estimated 188,000 miles of new high voltage transmission lines.

No estimates are available for the new pipelines, railways, barges, or ships needed to transport fuel materials to these powerplants.

Prospects of shortage

Forecasters of the Federal Government and the electricity industry expect the demand for electricity to continue to grow at an average rate of 7 percent a year with a doubling time of every 10 years. Most expect that the powerplants and transmission lines to supply this demand will be built and brought into operation as needed. Some observers do not share this optimism and none believes that such a rate of increase can continue for more than a few doubling times in any one geographical area.

Viewing the Nation as a whole, there seems to be no immediate shortage of electricity. However, electricity has been in short supply in some parts of the country during periods of peak demand and the quality of the supply has sometimes been reduced in meeting these peak demands. New York City, the Washington metropolitan area, parts of the Tennessee Valley are examples. For the summer of 1970, if peak demands again coincide with temporary outage of major powerplants or difficulties with transmission, some local shortages could again be experienced. Some believe that existing generating reserves are already at dangerously low margins on many electricity systems and pools, and much of this reserve is in old plants that are past retirement age.

Coal suppliers are not meeting their commitments to utilities and stockpiles at many plants are down to a 10 to 15 days supply in comparison with the desirable amount of several months or more. Labor unrest in rail transport and in coal mines thus could quickly lead to power shortages in some places.

Luck will be an important element in what happens this summer.

Looking ahead for the next two decades and projecting the present growth in demand for electricity, the supply of fuel materials of oil, coal, and uranium, but probably not for natural gas, will be adequately available in deposits accessible to the United States. However it is not as evident that the plant and equipment needed to work these deposits, to process the fuel materials and to transport them to the powerplants will be available and in operation when needed, particularly if there should be any substantial shift in the share of energy derived from each source. Also it is not as evident that the costs of those fuels will retain their present competitive status with one another which introduces further uncertainties.

The technology to build large steam electric plants fueled by coal, oil, gas, or uranium through the 1970's appears to be in hand or reasonably attainable assuming the trend toward design and construction of very large plants and high capacity transmission lines will continue and that objectionable environmental effects can be corrected. There is some doubt about the latter.

Some underlying assumptions

The expectations that the supply of electrical energy will keep pace with demand through the 1980's and 1990's appear to rest upon many assumptions. Some of those identified during the course of this study include the following:

1. *The demand for electricity will continue to grow as in the past.*

The historical growth of 7 percent, with a doubling time of 10 years, will continue. However, for 1968 and 1969 the loads have been about 9 percent.

The electricity industry will continue to promote greater use of electricity.

2. *The environment can absorb the wastes of doubling electric power every decade with whatever control is afforded by present technology.*

3. *Competition among fuels will remain effective.*

The competition among present fuels for steam-electric plants—oil, coal, gas, and uranium—will remain effective and that these fuels will be sufficiently available for utilities to change from one to another on short notices as prices dictate.

Such competition assumes also that time and capital will be available to provide the plant and equipment to work the deposits of these materials and do whatever fuel processing is necessary before delivery to the powerplants.

4. *Nuclear powerplants will generate much of the future electricity.*

Nuclear power will supply perhaps 25 percent of the electricity by the year 1980, 40 percent by 1990 and 60 percent by the year 2000. This in turn assumes that the breeding reactor will become commercially feasible and available by the mid 1980's and also that the costs of nuclear power will reverse their recent slight upward trend and will be competitive with fossil fuels. It assumes also that such plants can work within future limits governing emission of radioactive wastes and waste heat.

5. *Very large steam-electric plants will prove feasible to build and operate.*

Larger nuclear reactors, new generators, transformers, and components for the very large powerplants require a large step beyond existing techonology that could increase outage risks which are already large because powerplant equipment is not being built with sufficient quality control to assure reliable performance.

Further, much of the new capacity in the near future must come from the first generation of large nuclear powerplants which have still to demonstrate their working characteristics.

Unit sizes already are so large that one or two unscheduled shutdowns can cause a power shortage on an entire system.

6. *The economies of scale will be realized.*

The present trend toward fewer but larger steam-electric powerplants will continue and bring economies in operation not to be had with more but smaller powerplants.

7. *Sites for powerplants will be available as needed.*

Environmental effects of very large powerplants will be as tolerable to the public as the effects of smaller plants.

The waste heat, combustion products, and radioactive materials from very large powerplants or groupings of powerplants will not produce unacceptable environmental effects.

8. Rights-of-way for transmission lines will be available as needed.

The environmental effects of transmission lines will be or can be made tolerable enough so that rights-of-way for new lines can be obtained as needed. The trend toward fewer but larger powerplants brings with it the concentration of transmission lines in the vicinity of these plants.

9. The performance of transmission lines will be improved.

The technology of transmitting electricity over long distances without excessive loss of power or costs will be available.

Private interests with little or no Federal assistance will fund the requisite research and development to improve and demonstrate improvements in transmission line technology such as direct current transmission and use of superconducting cables.

10. Fossil fuels will not be diverted significantly to chemical markets.

Through the next several decades, the demand for coal, oil and gas as a raw material for chemical and food industries will not become so large as to divert these materials from fuel use, and that national conservation policies will not give a higher priority to non-fuel uses.

11. The electricity industry can finance the new plant and equipment needed.

Financing will be available to the privately, publicly, and cooperatively owned sectors of the electricity industry to build new powerplants and transmission lines as needed.

12. Delays will not get worse.

Schedules for acquiring plantsites, rights-of-way for transmission lines, manufacture of equipment, construction of powerplants and transmission lines can keep to schedules.

13. Economic concentrations in the industry will not violate antitrust laws.

The trend toward very large powerplants and consequent formation of large joint ventures to fund and operate them, and the parallel possible concentration of economic power in the financing of the vast future capital investments required by the electricity industry will not violate anti-trust legislation.

ISSUES OF ENERGY, ELECTRICITY, AND THE ENVIRONMENT

Many issues possibly warranting the attention of Congress appeared during the course of this study. These may be classified as operational, economic, technological, environmental, resource, and regulatory. Many of these issues are so interrelated that they could readily appear in more than one category. The issues identified during this study follow, posed in the form of questions.

Operational issues

1. National energy policy

To what extent is the marketplace still an adequate decisionmaking institution to assure adequate supplies of energy in appropriate form and quality?

Is a government policy needed to assure industry access to principal energy resources in the future, both domestic and imported?

What are the alternatives to Federal regulation of the entire energy market?

2. Economic and defense implications of fuel imports

What are the defense and economic implications of increasing imports of residual fuel oil and liquified natural gas for the east coast and the Midwest?

Are defense uses sufficiently different from civilian consumption to warrant separate policy decisions based on war-or-peace forecasts?

3. Planning for electric power

To what extent are present arrangements for regional planning in the electric power industry likely to assure the generating capacity will be available when and where needed?

What factors may upset the current forecasts of the Federal Power Commission as to future demand for and supply of electricity?

What are the consequences to home users and industry of bad planning?

4. Avoiding shortages

What changes may be needed in FPC authority and functions to fix the responsibility and authority for Federal action replanning and operations to supply electricity?

What short-term measures may be taken by the industry to avoid or alleviate the possible brown-out type shortages this summer?

Should advertising for appliances and other uses be curtailed?

What can be done to prevent further slippage in the scheduled time to build and put into operation large powerplants?

What is the effect of environmental protection requirements on new plant construction?

5. Powerplant sites and transmission rights-of-way

What, if any, Federal authority should there be to assist in, and, if necessary, obtain by legal action sites for large powerplants and rights-of-way for transmission lines?

How would the public's interest in preserving the environment be represented in such proceedings and balanced against the need for electricity?

6. Policy on promoting use of electricity

Should the FPC and the utilities continue with their philosophy of promoting additional per capita use of electricity? If not, what policy should replace it?

7. Policy on discouraging use of electricity

Should the Government adopt a policy of discouraging use of electricity, at least until present shortages are remedied, or in those places where, because of limitations on generating sites and transmission rights-of-way, additional power cannot be readily had?

Economic issues

A. Will changing costs and supply conditions be reflected in changing relative prices for different energy sources? What magnitude of relative price change will be needed to shift demand toward the relatively more abundant sources of supply?

B. Should electricity pricing schedules be revised to discourage rather than encourage marginal use?

1. Pricing electricity

To what extent should the price charged for electricity include:

(*a*) Costs of preventing and abating environmental effects of generating and transmitting electricity?

(*b*) Costs of dealing with the effects already caused by previous generation?

(*c*) Costs of requirements upon fuel suppliers that they in turn control and abate the environmenta effects of removing fuel materials from nature and processing them?

(*d*) Research and development to:

(1) Improve the efficiency of electricity generation?

(2) Improve waste control equipment and procedures?

(3) Develop new sources of energy for conversion into electricity?

2. Sale of AEC gaseous diffusion plants

What are the economic implications for the future of nuclear power of the terms and conditions of the sale by AEC of its gaseous diffusion plants to private industry, which has been proposed?

3. Trend toward larger powerplants

What are the effects upon the electricity industry of the trend toward fewer but larger powerplants that generate more electricity than is needed by an individual utility? What are the effects on the environment?

What is the implication of the trend toward larger powerplants and larger transmission facilities for the smaller power companies—privately, publicly, and cooperatively owned?

4. Requirements for capital

The electricity industry is capital intensive. What are the prospects that it can in fact raise $350 billion during the next 20 years for new plant and equipment? What will be the credit market impact of these heavy capital demands?

What estimates are there of the capital required by the energy industries over the next 20 years for their total estimated production? For that part of their production dedicated to the electricity industry?

What capital investment is expected for plant and equipment to move energy materials—rails for coal, pipelines for oil and gas, etc.—to supply the electricity industry of the 1980's and 1990's?

5. Economic limitations on growth in demand

What economic factors might influence the demand for electricity during the next two decades?

Technological issues

1. The breeder vector

What are the prospects that the breeder reactor will in fact be commercially available and economically attractive by the mid-1980's when it will be needed if projections of the role of nuclear power are to be met?

How much does this depend on Federal R. & D. funding?

2. Byproduct use of waste heat

What are the prospects for developing byproduct uses of large amounts of low quality heat as an alternative to discharging into the environment?

What economic measures could be taken to foster the byproduct use of heat?

Should nuclear utilities be encouraged to demonstrate such uses? To diversify their operations into such applications?

3. Technical limits to powerplant size

What limiting factors are there, if any, to the ultimate size of individual generating units, of individual powerplants (which may include several units)?

4. Efficiency of steam-electric plants

What measures can be taken to accelerate improvements in increasing the efficiency of steam-electric plants so that less heat is wasted?

When will MHD be commercially proven at the present rate of development?

Whose responsibility are these measures?

What is now being done by the utilities? By Government?

5. Prospects for the fuel cell

What are the prospects for the fuel cell as a competitive source of turbine generated electricity for larger users? What are the limiting factors such as catalysts availability, size of units, capital cost, etc?

Resource issues

1. Natural gas

With respect to fossil fuel energy resources available for generating electricity during the next three decades, natural gas appears to be in the weakest position. It is often found and produced in conjunction with oil.

To what extent are published reserve data, particularly on natural gas, extremely misleading, as some have claimed?

What is the potential for increased importation of natural gas? How do costs of importation compare with costs of domestic production?

2. Drilling for gas and oil

In view of the as yet unsolved environmental pollution problems which have arisen with respect to offshore drilling for oil and gas, is it desirable that exploration and discovery drilling for these fuels be encouraged on land in the contiguous states? If so, what incentive would be desirable? Should offshore drilling be further restricted or halted until more adequate environmental safeguards are developed?

How can natural gas discovered on the Alaskan North Slope be most wisely used?

3. Coal production

Although coal resources overall are very large there are increasing indications that production by coal mines in the present large producing areas has not been very responsive to the condition of increased demand, slightly higher prices, and generally reduced stocks on hand. This situation poses several related questions:

(*a*) To what extent are present mining establishments even more overcommitted (with respect to probable demand, present and future) for low-sulfur coals than for other types?

(*b*) What major developments are now in motion or firmly planned for development of large but only slightly developed resources of low-sulfur sub-bituminous coals and lignite found in the Northern Plains and Mountain States?

(*c*) Is it desirable that there be private or public stimulation of the mining of such coals in those areas?

(*d*) Prospectively, what provisions would need to be made, and at what capital cost for production and transportation? Is there now adequate technology for reclamation of these sub-humid lands after strip mining and at what cost?

Environmental issues

1. Control of sulfur dioxide

Many local air pollution control agencies are restricting the use of fossil fuels that contain sulfur. Are fossil fuel supplies of low sulfur content available presently and in the future to meet federally recommended air quality standards for sulfur oxides?

If not, who has the responsibility for expediting development and demonstration of methods and equipment to remove sulfur oxides from stack gases of power plants? What priority should be given to this?

Concerning the effect upon fossil fuel supply of sulfur content limitations, what are their effects upon present import of residual fuel oil? What are the projected demands for low-sulfur oil from foreign sources—assuming no limitation of import by government action?

2. Bypassing the use of electricity

As a means of reducing consumption of electricity, and thus reduce environmental effects, to what extent could or should Government policies seek to encourage the direct conversion of fuels to mechanical energy or heat energy in preference to converting fuel into electricity which then is converted into mechanical or heat energy, with the inevitable 60 percent loss of heat energy at the first conversion step?

3. Comparison of nuclear and fossil fuels

What definitive Government analysis of the comparative environmental effects of nuclear and fossil fuels for generation of electricity has been performed? Is one feasible? Who should do it?

How would electricity generated from nuclear versus fossil fuels compare in cost if each system had to meet a "zero pollution" standard?

4. A policy of zero pollution?

Should the Federal Government adopt and enforce a national policy of zero pollution from all new power generating facilities? "Zero pollution" means no emissions in excess of Federal standards.

5. Evaluating environmental effects

What reasons are there to develop a uniform method of evaluating environmental effects of major power projects, perhaps a method based upon cost-benefit analysis?

What weight should environmental considerations carry in decisions by utilities as to where and how to generate electricity and to transmit it, and associated review and decisions by Government agencies?

6. Administration

To what extent would the users of electricity, the utilities, and the environment be better served by consolidating in a single Federal office and in single State counterpart offices whatever Government action is related to protection of the environment?

7. Protection of amenities

Is there needed a national policy for amenity protection and supporting legislation so that the Federal Government would set standards and criteria to guide State, local, and regional agencies in deciding where power facilities and transmission lines should be located and their appearance? Who would apply and enforce such standards? How can State governments cause zoning agencies to give special attention to siting of power generation and transmission facilities?

8. Transportation of oil

To what extent should the environmental problems from long-distance transportation of oil be considered in deciding what fuels will be used by steam-electric powerplants?

9. Costs of "clean electricity"

How much will it cost to keep the environmental effects of generation and transmission of electricity, including effects of the fuel suppliers, within limits acceptable to society? How should these costs be divided between:

(*a*) The taxpayers—Federal, State, and local.
(*b*) The ratepayers.
(*c*) The utilities, from income in excess of expenses.

How much agreement is there concerning costs of controlling environmental effects of generation and transmission of electricity for:

(*a*) What capital and operating costs should be recognized by State public utility commissions in the setting of rates?
(*b*) The amount of those costs.

10. Reclaiming strip mines

How should the costs of reclaiming abandoned deep and pit mines in the coalfields be divided between present coal producers and the taxpayer?

11. Tax incentives

To what extent should local agencies of Government be encouraged to give special tax benefits for capital investments that reduce the environmental effects of generating and transmitting electricity?

12. Equally vigorous standards

Should all limits for emissions from powerplants have as rigorous a safety factor as those set by AEC for emission of radioactive effluents?

13. Coal mining in the Rockies

Concerning plans to use low-sulfur coal in the Rocky Mountain area, what is known of the likely environmental effects of mining these coal-fields in this topography?

Regulatory issues

1. How should Federal agencies consider social and economic values in the regulation of utilities and also the public interest for such matters as:

(*a*) Balanced energy economy.

(*b*) Efficiency in allocation and use of the Nation's natural resources of fuel, land, air, and water?

(*c*) Social performance of the electric utility industry in contributing to the Nation's overall economic and environmental welfare.

CONGRESSIONAL INTEREST IN ENVIRONMENTAL POLLUTION

Many committees of Congress have examined various aspects of environmental pollution and in doing so have helped to illuminate the nature and extent of the effects of generating electricity upon the environment. In the House, the Committee on Education and Labor, the Committee on Government Operations, the Committee on Science and Astronautics, the Committee on Interstate and Foreign Commerce, and the Committee on Public Works have held hearings.

In the Senate, the Committees on Commerce, District of Columbia, Government Operations, Interior and Insular Affairs, and Public Works also have held hearings on matters such as air and water pollution and environmental quality. The Joint Committee on Atomic Energy likewise has done so and during 1969 and 1970 has held extensive hearings specifically on the environmental effects of generating electricity. A list of the hearings and publications of these committees appear in appendix II.

This extensive background of hearings and reports makes it possible to proceed more directly to laying out the overall environmental effects of all of the industrial operations involved in the generating of electricity, the supplying of fuel to the powerplants, and the transmission of the electricity to the using areas; and to identifying and examining the economic factors involved.

Is There an Energy Gap?

AN OVERVIEW

Until quite recently it was assumed that because the United States had large reserves of fuels in the form of coal and oil shales and nuclear fuels—provided the breeder reactor can be perfected, there was little prospective shortage of available, useful energy. Recently warnings are heard that the United States may be passing from a situation of energy abundance into one of energy scarcity. If so, this would have grave implications for prospects of further increasing the standard of living and also increasing the productivity of labor. The imports of residual fuel oil to the northeastern United States, present plans to import it into the Midwest, and future plans to import liquified natural gas may reflect a decrease in availability of energy from domestic sources to meet rising demands.

As for electricity, some local shortages during peakload periods of last summer and this past winter have occurred. These shortages seem likely to be repeated during 1970, particular should peak demands coincide with interruption of the output of large powerplants. The shortages are likely to be aggravated in those densely populated parts of the country that use large amounts of electricity but where land is not readily available for either large new powerplants or transmission lines. Some shortages may occur because of shortages in the supply of coal and because of changes from coal to oil or gas because of increasingly severe limitations upon the permissible amount of sulfur in coal burned in powerplants. Present restrictions on imports of residual fuel oils and signs of a shortage in natural gas seem likely to complicate the fuel supply for large new powerplants as they are ordered and and built.

SOME VIEWS

The past year has produced wide-spread concern over the imminence and severity of possible shortages in electricity.

Lee C. White, past Chairman of the Federal Power Commission, in his last official press conference at the FPC, said that his biggest disappointment was "the inability to persuade the electric-power industry and the Congress that we are rushing, I am afraid almost headlong, into a situation where we may not have enough electric energy in this country to go around."

John T. Ryan, commissioner, New York State Public Service Commission concerning the ability of the Consolidated Edison Co. of New York to meet electric demands this summer, he said:

> * * * Based on 1969 experience, if the peak load forecast for 1970 is reached in June and the level of system deratings experienced in 1969 again prevails, the capacity available to meet forced outages would be very small or even negative.

Glenn T. Seaborg, Chairman of the U.S. Atomic Energy Commission, in testimony before the Joint Committee on Atomic Energy on October 29, 1969:

* * * In the years ahead, today's outcries about the environment will be nothing compared to the cries of angry citizens who find that power failures due to a lack of sufficient generating capacity to meet peak loads have plunged them into prolonged blackouts—not mere minutes of inconvenience, but hours—perhaps days—when their health and well-being and that of their families, may be seriously endangered.

Philip Sporn, member of the National Academy of Engineering and former president of the American Electric Power Co.:

Recently, the expansion of electric-power generating capacity has been stopped or delayed at a growing number of points in the United States. These delays are a result of well-intentioned activities that have caused rising public anxiety about the environmental impact of the operation of electric generating stations and, particularly, of atomic generating plants. * * * Because of delays in the installation of new generating capacity many major power grids are without comfortable reserves to meet emergencies. And if this opposition to expanding our electric energy supply continues, surely we are going to bring about a catastrophic situation. This we simply must avoid. The implication this carries for our national policy is clear. A major effort is called for to make possible continuing and expanding use of energy by man and to assure compatibility of this energy with a healthy environment.

John A. Carver, Jr., Commissioner, Federal Power Commission:

A crisis exists right now. For the next three decades we will be in a race for our lives to meet our energy needs.

David Freeman, Director, Energy Policy Staff, Office of Science and Technology:

* * * anyone who looks at the facts on power supply today and doesn't believe that the industry is in trouble is living in a dream world.

Generating reserves are already at dangerously low margins on many systems and pools, and much of it is old plants that are past retirement age.

* * * the real question is not whether we will have a power shortage in the near future, but rather whether the shortage of the past year will intensify.

Charles A. Robinson, Jr., staff counsel to the National Rural Electric Association:

America's electric utility systems are currently attempting to remedy what is certainly the most critical power shortage since World War II, if not the worst in the entire 82-year history of the industry.

SOME REPORTED POWER SHORTAGES

Shortages of generating capacity resulting from various causes have produced relatively critical situations in electric power supply in several areas of the United States in recent years. The following are examples of shortages of sufficient severity to cause concern.

During the 1969 summer peak load season, electric systems comprising the Pennsylvania-New Jersey-Maryland interconnection (PJM pool) ordered 3-percent voltage reductions on five separate occasions and 5-percent reductions on six occasions, including one general public appeal for voluntary load curtailment. The actual PJM summer reserve margin was 4.5 percent compared with the previously forecast 11 percent and a desirable level of 20 percent.

An emergency meeting of PJM area regulatory commissions and utility executives representing Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia was held on December 23, 1969, to consider the equally critical situation developing for 1970 and 1971. All possible remedies were evaluated, including cold reserve identification, advancement of construction schedules, postponing retirements, and identification of customer-owned capacity. All of

these possibilities were found to have been already exhausted. Moreover, all U.S. power pools east of Chicago were contacted without discovering any firm summer reserves. The PJM utilities were then asked by the commissions to order 883,000 kilowatts of additional gas turbine capacity for 1971 availability, but U.S. manufacturing capacity in this area was found to be already saturated.

On December 16 and 17, 1969, and on January 8 and 9, 1970, the PJM pool again ordered 5-percent voltage reductions because of unscheduled loss of capacity in Pennsylvania and New Jersey and the need to avoid a cascading failure by helping other pool to the south and west which were in even more serious condition.

These situations resulted from a combination of circumstances—a greater increase in summer peak demands than projected and significant delays in getting new capacity and new transmission lines in service, notably the more than 2-year delay in the Oyster Creek nuclear plant and a delay in the start up of the large Keystone Unit No. 2 coal-fired unit, which prevented its dependable use to help meet the summer loads for which it had been scheduled.

The Consolidated Edison system, serving metropolitan New York, experienced serious power shortages on several days during July, August, and September 1969, finding it necessary to reduce voltage by as much as 8 percent and in several instances to appeal to the public for a voluntary cutback in its use of electricity. The situation was aggravated by an unusual pyramiding of losses of several of its larger generating facilities during peak demands and by the absence of strengthened interconnections with neighboring utilities which had been scheduled for earlier completion.

On several occasions during the summer of 1968, the Chicago, Detroit, New York, and New England areas resorted to voltage reductions as a means of reducing loads because of deficiencies in generating capacity needed to supply peak loads on particular days. The Commonwealth Edison Co., serving Chicago and northern Illinois, was particularly short of supply during the summer of 1969 because of the delay in the completion of the new 715 mw. nuclear unit under construction in the company's Dresden generating station. Arrangements were made to import power over a wide geographic area of the Midwest and Central East regions. Fortunately the absence of extremely hot weather during the summer helped to avert a more serious situation.

During the past winter, TVA and many other systems were forced to reduce voltage on their systems to meet peak loads.

During this period, even the highly controversial 100 mw. unit owned by Hoosier Energy, Inc., an REA financed cooperative in Indiana, was pressed into service to help avert disaster on the TVA system. This unit had been under legal attack from Indiana power companies for 10 years. For many months it had remained closed down pursuant to a Federal court injunction. So critical was the need, however, that on January 8, and for several days following, the unit was operated by mutual agreement of all parties.

Chairman Nassikas, of the FPC has indicated that 22 major systems reported summer reserves in 1969 of less than 10 percent. Specifically, he mentioned the Southern Co. system (1.6 percent), which serves Alabama, Mississippi, and Georgia; The Cleveland Electric Illuminat-

ing Co. system (3.1 percent); and the American Electric Power Co. system (5.1 percent), which serves parts of Virginia, West Virginia, Ohio, Kentucky, Tennessee, Michigan, and Indiana. The FPC further reported in November 1969 that 39 out of 181 major systems faced the winter with less than 10 percent reserves.

PROSPECTS FOR FUTURE SHORTAGES

Forecasts for the immediate future are not a great deal more optimistic. According to Maryland PSC chairman, Williom O. Doub, utilities nationwide will face the 1970 summer peak load with overall reserves of 16 percent compared with 32 percent in 1960, and a desirable level, 20 percent. Doub also has forecast 1971 PJM summer reserves at 15 percent or less, even if all planned new gas-turbine units are installed on time. Consolidated Edison Co. of New York plans to use "barge power" for several years to meet summer peaks. Gas-turbine generators will be mounted on barges and towed around Manhattan Island to be plugged in wherever and whenever the need is greatest.

Under these minimum reserve conditions, any unanticipated large scale loss of generation or transmission at the time of peak load could result in power failures over a wide geographical area unless load is quickly dropped.

On the other hand, the Edison Electric Institute is more optimistic. EEI president, A. H. Aymond, in January 1970 asserted that in the summer of 1969 the gross margin of capability over demand was 16.9 percent for the contiguous United States, which is adequate to assure reliable service. He noted that some regions or areas may have insufficient reserves when the gross national reserve is not spread evenly. However, none of the eight power-supply regions had less than a 10.7-percent margin. Conceding this to be a bit on the low side, he expects that for 1970 and 1971 the overall summer margin will be 18.4 percent. This is not to say, he concluded, that certain systems in limited areas may not have difficulties in 1970 because of inadequate reserves. "The reason for this, in most cases, is not that the utilities did not plan for the future, but that events or intervention beyond their control conspired to prevent completion of additional capacity within reasonable time."

CONSTRUCTION DELAYS AS A FACTOR

At present a fossil-fueled powerplant requires 4 years to build from the placing of the contracts and a nuclear-powered plant requires a year or so more.

Much of the possible shortage of electricity will be attributed to delays in getting new powerplants built and into routine operation. The electric utilities face a vast construction program of very large powerplants with many possibilities of delays. Chairman Nassikas of the Federal Power Commission has called attention to the probability of increasing lead times for construction and the extended breaking in periods for the large units that will be used during the 1970's and 1980's. Even after these are in regular operation, he notes the possibilities of longer times out of service because of maintenance.[1]

[1] Hearings before the Senate Commerce Committee, Jan. 1, 1970, p. 37 of prepared statement.

A survey by the Edison Electric Institute for the Federal Power Commission of 85 large steam generating plants of 200 megawatts size or over installed during the years 1966 to 1968 indicated that about two-thirds of the total were delayed in being put into service. All four nuclear units scheduled for installation during this period were delayed for periods of 3, 9, 11, and 12 months, respectively. Of the 51 fossil fired units which were delayed during the period, only five extended 6 months beyond scheduled in-service dates and three of these were purposely deferred because of changes in load requirements.

Equipment component failures and shortage of construction labor were the most frequent causes of delays found in this survey. Late delivery of major equipment and construction labor strikes were the next greatest causes. Over 80 percent of all the delays were attributable to these four categories. Late delivery of equipment was expected to be the prime reason for delay during the period 1969–71. No delays were attributed so far to public opposition to sites for powerplants because of their environmental effects and only four delays were caused by regulation. However, the institute cautions that future delays attributable to environmental problems may well be more serious and more widespread than at present. Therefore, it is imperative to work out a basis for resolving conflicting viewpoints about use of land for power and other purposes.

Looking ahead through 1976, the Federal Power Commission expects 138 fossil-fired steam electric plants and 64 nuclear units of 300 megawatts capacity and over to come into service. At present, 27 of the fossil-fired units totaling 15,000 megawatts are reported as delayed, and 27 nuclear units totaling 21,000 megawatts are also delayed as of January 30, 1970. Eighty-three fossil-fired units and 37 nuclear units are reported on schedule. However since most of these units are scheduled for service in later years, FPC thinks it likely that some of them too will experience delays and fail to meet presently scheduled service dates.[1]

Wilson M. Laird, director of the Office of Oil and Gas, Department of the Interior, attributes some of the trend toward delay to the headlong rush to order nuclear powerplants in 1966 and 1967 followed by a precipitate return to ordering coal-fired plants in 1969. This, he says, threw the expansion plans of both the coal and electric power industries into disarray. "Now both are off schedule; perhaps as much as 2 years have been lost by the premature commitment to nuclear power, and it shows in the reduced margin between demand for electric power and the capacity to supply it."[2]

DELAYS IN TRANSMISSION FACILITIES

Both the adequacy and reliability of electric service depends upon the timely construction of the transmission lines to carry electricity from the powerplants to the areas of use. With the trend towards fewer but larger powerplants, the availability of transmission capacity becomes increasingly important. Delays in the completion of such lines necessarily increases the vulnerability of an electric utility both to the

[1] Statement of John N. Nassikas, Chairman, Federal Power Commission, before the Senate Commerce Committee, Jan. 30, 1970.
[2] Wilson M. Laird, remarks before the Institute on Petroleum Exploration and Economics, Dallas, Tex., Mar. 5, 1970. Department of the Interior news release, Mar. 5, 1970, p. 2.

type of power failure that blacked out much of the eastern United States in 1965, and to power shortages. Temporary power shortages can occur when the construction of powerplants and transmission lines get out of step.

There are delays.

For example, a high-voltage transmission line to connect southeastern New York with a system in the mid-Atlantic States was first scheduled for operation in 1967. It probably will not be available for service by the summer of 1970 because of difficulties in acquiring rights-of-ways. Again, a high-voltage transmission line to connect the Pennsylvania-New Jersey-Maryland power pool with New York City, which might have averted the 1965 blackout, has still to be completed. Rights-of-way are increasingly difficult to get through densely populated areas. Public opposition to construction of transmission lines, particularly in the densely populated East, may prove a greater impediment to the future supply of electricity than opposition to powerplants sites.

ENERGY FOR THE ELECTRICITY INDUSTRY

In 1970 the Nation's electrical powerplants are expected to generate some 1.52 trillion kilowatt hours of electrical energy. None of this energy is created within the plants. Rather it must come from external sources and be converted into electricity. Without the energy from water passing through turbines or from heat released by burning coal, oil or gas, or from fissioning nuclear materials, our electric powerplants would stand idle and useless.

Of principal concern, therefore, to any review of the electricity industry is the supply of energy for the power stations. Since by far the largest part of this input energy presently comes from the fossil fuels—oil, coal, and gas—the supply and demand for these commodities, their production, the environmental effects of that production and corrective measures for those effects, require consideration.

Since the electricity industry must compete with other users of basic energy resources, an appropriate starting point for this chapter is to look at some recent estimates for supply and demand for energy in the United States.

SUPPLY-DEMAND FORECASTS AND THEIR FALLIBILITIES

During the past several decades many observers of supply and demand for energy resources have forecast future trends. In examining these forecasts, two related points are worthy of notice. First of all, there has been a substantial short-fall in previous careful estimates and thus current projections may be met with skepticism. The Paley Commission in its 1952 report[1] included a projection of the production of electricity in 1975. The projection by the Commission of the extent to which the several possible sources would then be used is shown here in table 3. It may be noted that the projected 1975 total of 1,400 billion kilowatt-hours had been exceeded by 1968. Generation of electricity with hydropower was projected at more than 21 percent of the total in 1975 but in 1968 had declined to less than 17 percent. Fuel oil and natural gas were each projected as supplying about 11 percent of the total in 1975. For oil, this estimate was very nearly the same percentage it supplied in 1950—it has in fact, according to recent data (1968), fallen significantly below that level. In the case of gas, the projection involved moderate decline, as compared with 1950, in its contribution to the total. To date, that projected decline has not taken place; instead, in recent years natural gas has supplied more than one-fifth of the total energy resources used to generate electricity;

[1] "Resources for Freedom," a report to the President by the President's Materials Policy Commission, vol. III, "The Outlook for Energy Resources," June 1952.

this aspect of the demand for gas has performed very differently from what was estimated in 1952. Finally, use of nuclear fuel was not projected—even in 1968 the table presented above (table 2) does not estimate its development in that year, but blankets it in with coal as a miscellaneous resource.

TABLE 3.—PRIMARY ENERGY SOURCES AND PRODUCTION OF ELECTRICITY, 1950, AND A POSSIBLE PATTERN OF SOURCES AND PRODUCTION, 1975

Source	Consumption of basic energy		Kilowatt-hour production (billions)	
	1950	1975	1950	1975
Coal	[1] 113	[1] 320	191	800
Gas	[2] 777	[2] 1,600	55	150
Oil	[3] 93	[3] 300	42	150
Total thermal production			288	1,100
Hydroelectric	[4] 19	[4] 60	101	300
Grand total			389	1,400

[1] Millions of short tons.
[2] Billions of cubic feet
[3] Millions of barrels.
[4] Millions of kilowatts capacity.

Source: "Resources For Freedom," President's Materials Policy Commission (Paley Commission), 1952, vol. III, p. 36.

YEAR 2000 ESTIMATES—THEIR RELIABILITY

With that background, it is not to be anticipated that projections by the Department of the Interior to the year 2000 which are found in table 5 are likely to prove to be more than rough approximations of what is yet to develop over the next three decades. Whereas coal provided more than half of the resources used to generate electricity in 1968, it is estimated that coal will contribute only about 30 percent of the total in year 2000. The comparative contribution of oil to the larger supply of electricity in 2000 is estimated at only 5.5 percent, against 7 percent in 1968. Use of natural gas would decline from its present 23 percent of the total to 4.8 percent. Hydropower would decline comparatively to 7 percent from the recent 17 percent of the total. Nuclear power as a resource for the generation of electricity would, by that recent estimate, increase from a barely significant factor of less than 1 percent of the total in 1968 to the dominant position of 52.5 percent in the year 2000.

Now, and as projected 30 years hence, geothermal sources, and direct solar energy are both indicated as probably of little significance as a resource in the generation of electricity. Much the same may well be the case for tidal power, considering the substantial lag time involved.

In any case attempts to project energy consumption or requirement at future dates are relatively numerous. Because of differing assumptions used, they are not for the most part directly comparable. Tables 6 and 7, provide some information on a number of projections made from the time of the Paley Commission and prior to those shown in table 5.

TABLE 4.—ELECTRIC ENERGY PRODUCTION AND INSTALLED GENERATING CAPACITY, BY CLASS OF OWNERSHIP AND TYPE OF PRIME MOVER: 1940–68

[Production for calendar years; other data as of Dec. 31. Prior to 1965, excludes Alaska and Hawaii. See also Historical Statistics, Colonial Times to 1957, series S 15–35 and S 44–69]

Item	1940	1945	1950	1955	1960	1965	1967	1968 [1]
Production (bil. kw.-hr.)	180	271	389	629	842	1,158	1,317	1,433
Industrial plants [2]	38	49	60	82	88	102	103	106
Electric utilities (for public use)	142	222	329	547	753	1,055	1,214	1,327
Privately owned [3]	125	181	267	421	579	809	928	1,019
Percent of utility production	88.4	81.3	81.1	76.9	76.8	76.7	76.5	76.8
Publicly owned [3]	16	42	62	126	175	246	286	308
Municipal	6	10	15	26	37	50	58	64
Federal	9	28	40	89	112	145	162	171
Cooperatives and other	1	3	6	11	26	51	66	74
Source of energy (percent):								
Coal [4]	54.6	51.7	47.1	55.1	53.6	54.5	52.6	52.5
Oil	4.4	3.5	10.3	6.8	6.1	6.1	7.4	7.8
Gas	7.7	8.9	13.5	17.4	21.0	21.0	21.8	23.0
Hydro	33.4	35.9	29.2	20.7	19.3	18.4	18.2	16.7
Per kw. of capacity (kw.-hr.)	3,552	4,440	4,776	4,779	4,484	4,469	4,510	4,570
Installed capacity (mil. kw.)	51	63	83	131	186	255	288	309
Industrial plants [2]	11	13	14	16	18	18	19	19
Electric utilities (for public use)	40	50	69	114	168	236	269	290
Privately owned	34	40	55	87	128	178	204	220
Percent of utility capacity	86.2	80.4	80.1	75.9	76.5	75.2	75.6	75.8
Publicly owned [3]	6	10	14	28	40	59	66	70
Municipal	3	4	5	8	11	15	18	19
Federal	2	5	7	17	22	32	34	35
Cooperatives and other	(5)	1	2	3	6	11	14	16
TYPE OF PRIME MOVER								
Electric utilities (for public use):								
Number of plants, total [6]	3,918	3,886	3,867	3,587	3,435	3,290	3,378	3,439
Hydro	1,474	1,505	1,458	1,381	1,331	1,231	1,211	1,214
Steam	1,153	1,057	1,051	1,045	1,060	1,068	[7] 1,149	[7] 1,200
Internal combustion	1,291	1,324	1,358	1,161	1,044	991	1,018	1,025
Production (bil. kw.-hr.)	142	222	329	547	753	1,055	1,214	1,327
Hydro (bil. kw.-hr.)	47	80	96	113	146	194	222	222
Steam (bil. kw.-hr.)	93	140	230	430	603	856	988	1,105
Internal combustion (bil. kw.-hr.)	2	2	4	4	4	5	5	
Installed capacity (mil. kw.)	40	50	69	114	168	236	269	290
Hydro	11	15	18	25	32	44	48	51
Steam	28	34	49	87	133	189	[7] 217	[7] 235
Internal combustion	1	1	2	2	3	3	4	4

[1] Preliminary.
[2] Plants of 100 kilowatts and over, including stationary powerplants of railroads.
[3] Noncentral stations included only in total prior to 1955; distributed to other publicly owned classes thereafter.
[4] Includes small percentage from wood and waste and also, in past few years, from nuclear fuel.
[5] Less than 500,000 kw.
[6] Each prime mover type in combination plants counted separately.
[7] Includes gas turbine capacity: 3,000,000 kilowatts in 1967 at 140 plants and 6,000,000 kilowatts in 1968 at 197 plants.

Source: Statistical Abstract of the United States, 1969. U.S. Department of Commerce, 90th ed., p. 511.

TABLE 5.—RESOURCES USED TO GENERATE ELECTRICITY

	Percent of total		Quantities [1]	
	1968	2000	1968	2000
Coal	51.9	30.2	297	1,000 (millions of tons).
Oil	7.0	5.5	187	800 (millions of barrels).
Gas	23.0	4.8	3.1	4 (trillions of cubic feet).
Nuclear power	.8	52.5	----------	
Hydropower	17.3	7.0	----------	

[1] Assuming no changes in generation technology.

Source: Statement of Mr. Harry Perry, research adviser to the Assistant Secretary for Mineral Resources before the Joint Committee on Atomic Energy, Nov. 4, 1969, in "Environmental Effects of Producing Electric Power." Hearings before the Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, p. 321.

TABLE 6.—PROJECTIONS OF DOMESTIC ENERGY CONSUMPTION

Source and publication date	Year: 1975	Year: 1980	Year: 2000	Data on—: Population	Data on—: Fuel form	Data on—: Fuel function	Data on—: Electricity
Paley (1952)	X			X	X	X	X
Putnam (1953)		X	X				
Bureau of Mines (1956)		X				X	
Interior-McKinley (1956)		X			X		
Teitelbaum (1958)		X		X	X		X
Lamb (1959)		X		X	X		X
Sporn (1959)	X		X	X	X		X
Schurr and Netschert (1960)	X			X	X	X	X
Searl (1960)		X	X	X	X		
Weeks (1960)		X	X		X		
Texas Eastern Transmission Corp. (1961)		X		X	X	X	X
Hubbert (1962)		X	X				
Atomic Energy Commission (1962)		X	X	X			X
Lasky Study Group (1962)		X		X	X		X
Landsberg (1963)		X	X	X	X	X	X

Source: Energy R. & D. and National Progress prepared for the Interdepartmental energy study by the Energy Study Group under the direction of Ali Bulent Gambel, 1964, p. 16.

TABLE 7.—U.S. ENERGY AND PETROLEUM REQUIREMENTS FOR 1980[1]

Source	Date	Total energy quad. B.t.u.	Oil: Million barrels per day	Oil: Percent total	Gas: Trillion cubic feet	Gas: Percent of total
National Fuels and Energy Study Group[2]	1962	82.0	16.7	41	21.2	28
Department of Interior	1965	85.9	17.5	40	25.6	31
Pan American Petroelum Corp.[2]	1966	87.0	18.6	43	28.0	33
American Gas Association[2]	1966				27.2	
Stanford Research Institute[2]	1967	92.0	18.2	39	27.9	31
The Gas Industry Committee	1967				28.6	
First National City Bank of New York[2]	1967	87.2	17.2	38	23.6	28
The Petroleum Industry Research Foundation	1968	92.0	18.0	39	28.0	31
Texas Eastern Transmission Corp	1968	97.8	18.9	41	30.8	33
Humble Oil & Refining Co	1968	97.3	18.2	37	29.8	32
Department of Interior (current survey)	1968	88.1	18.2	41	24.6	29

[1] Explanation provided by the Department of the Interior included: "Energy projection claims the attention of many in government and industry alike. Shown below are extracts from 10 recent studies by various sources giving estimates of the 1980 requirements of the United States for oil, gas, and total energy. Totals arrived at in this survey are shown as the last item for purposes of comparison. Although not directly comparable because of differing assumptions used, the estimates do provide a useful guide to current opinion on the energy outlook."

[2] Oil and gas consumption obtained by converting B.t.u. to barrels and cubic feet at the rate of 5,400,000 B.t.u. per barrel and 1,035 B.t.u. per cubic foot.

Source: "United States Petroleum Through 1980," U.S. Department of the Interior, 1969. p. 5.

TABLE 8.—FORECASTS OF TOTAL ENERGY REQUIREMENTS

[Trillions of B.t.u.'s]

Source document	Date of publication	Base years	Base value	1970	1975	1980	1985	2000
CGAEM [1]	1968	1947–65	30,838 52,350	64,444	79,611	97,825	119,597	
EUS [1] [2]	Sept. 1967	1960–65	41,453 50,314	60,827	79,944	93,374	118,126	
N.F. & E.S	Sept. 1962	1961	44,064			[3] 82,000		
RAF	Sept. 1962	1960	45,250	60,190		79,200		135,200
PEC	Dec. 1968	1947 1962	33,168 47,897			85,934		
ER	Dec. 1962	1907–60	14,600 44,900			[4] 61,000		
OEUS	Oct. 1968	1950–65				[5] 97,000		
USP	July 1968	1965	54,000			88,100		
EMUS	July 1968	1947–65	33,168 53,791	64,276	75,605	88,075		168,600
PCCP [2]	May 1968	1948–65	54,000			[2] 83,900 91,000		[2] 158,951 155,000
FFF	October 1960	1953	41,000		73,000	86,200		170,000
TCUSEC [6]	1968	1960	48,200			90,300 (99,700)		174,000 (213,000)

[1] Hydro accounted for at kw.-hr. energy equivalent.
[2] Excludes nonfuel uses.
[3] Consensus of 11 forecasts.
[4] Minimum.
[5] Converting their 17,000 million barrels of oil equivalent to B.t.u. 5,800,000 B.t.u. per barrel.
[6] GNP growth rate at 3.5 percent per year and (4.0 percent per year.

Source: "Review and Comparison of Selected United States Energy Forecasts," Op. cit., p. 12.

In March 1970, the Office of Science and Technology, of the Executive Office of the President released a report prepared for the Energy Policy Staff of OST by the Battelle Memorial Insitute.[1] Its primary purpose was to analyze the adequacy of existing, published energy forecasts for public policy purposes. The essence of nineteen recent energy forecasts published by private organizations, government agencies and individuals was collected and studied. Perhaps not unexpected in view of the differences in terminology, coverage and assumptions, significant deficiencies for policy planning purposes were found in the existing forecasts studied. In particular, most of the forecasts were prepared prior to the recent concern with environmental quality and hence do not reflect the possible effects of developing environmental policies on energy supply and demand.

The Study Group examined the following 19 forecasts:

NF&ES---------- Report of the National Fuels and Energy Study Group on Assessment of Available Information on Energy in the United States, Committee on Interior and Insular Affairs, U.S. Senate, September 1962.

ERDNP-------- Energy R. & D. and National Progress Interdepartmental Energy Study, Energy Study Group, Ali Bulent Cambel, June 1964 (U.S. Government Printing Office).

USP------------ United States Petroleum Through 1980, U.S. Department of the Interior, Office of Oil and Gas, July 1968.

FGNP---------- Forecast of Growth of Nuclear Power, WASH–1084, U.S. Atomic Energy Commission, Division of Operations Analysis and Forecasting, 1967.

[1] "A Review and Comparison of Selected United States Energy Forecasts," by Pacific Northwest Laboratories of Battelle Memorial Institute, December 1969, Washington, D.C., U.S. Government Printing Office, 1970. 79 pages.

PEC----------- Patterns of Energy Consumption in the United States, William A. Vogely, Division of Economic Analysis, Bureau of Mines, U.S. Department of the Interior, 1962.

GUPIP-------- Gas Utility and Pipeline Industry Projections, 1968–72, 1975, 1980, and 1985, Department of Statistics, American Gas Association.

FNGR--------- Future Natural Gas Requirements of the United States, Future Requirements Agency, Denver Research Institute, University of Denver, vol. 2, June 1967 (under the auspices of the Gas Industry Committee).

CGAEM------- Competition and Growth in American Energy Markets, 1947–85, Texas Eastern Transmission Corp., 1968.

NPS---- ------ National Power Survey, Federal Power Commission, 1964, U.S. Government Printing Office.

ER------------ Energy Resources, a report to the Committee on Natural Resources, M. K. Hubbert, National Academy of Sciences, Publication 1000–D, National Research Council, 1962.

EUS----------- Energy in the United States, 1960–85; Michael C. Cook, Sartorius & Co., September 1967.

RAF----------- Resources in America's Future, Landsberg, Fischman, & Fisher, Resources for the Future, Inc., John Hopkins Press, 1963.

TCUSEC------- Technological Change and United States Energy Consumption, 1939–54, Alan M. Strout (unpublished thesis) (energy projection portion of the thesis). University of Chicago.

EMUS--------- An Energy Model for the United States Featuring Energy Balances for the Years 1947–65 and Projections and Forecasts to the years 1980 and 2000, Bureau of Mines, IC 8384, July 1968, U.S. Department of the Interior.

OEUS---- --- Outlook for Energy in the United States, Energy Division, The Chase Manhattan Bank, N.A., October 1968.

ESDNR------- Economic Strategy for Developing Nuclear Reactors, Paul W. MacAvoy, Massachusetts Institute of Technology Press, 1969.

FFF----------- Fossil Fuels in the Future, Office of Operations Analysis and Forecasting, U.S. Atomic Energy Commission, Milton F. Searl, 1960.

PCCP---------- Projections of the Consumption of Commodities Producible on the Public Lands of the United States 1980–2000, prepared for the Public Land Law Review Commission, Robert R. Nathan Associates, Inc., Washington D.C., May 1968.

CNP----------- Civilian Nuclear Power—A Report to the President, U.S. Atomic Energy Commission—1962 (and 1967 supplement).

As pointed out in the foreword of that study, the formulation of energy policy inevitably depends upon expectations regarding energy supply and demand. Yet in regard to forecasts of total energy requirements, or probable requirements for electric power generation or fuel needed for such generation, the range of estimates for a particular year in the future, say 1980, is rather wide, as may be noted from tables 8 and 9.

TABLE 9.—FORECASTS OF U.S. ELECTRIC UTILITIES FUEL REQUIREMENTS

[Trillions of B.t.u.'s]

	1970	1975	1980	1985	2000
EMS	14,547	19,011	24,258		72,291
CGAEM	13,473	18,198	24,024	31,251	
NPS	15,190		27,566		
EUS	14,207	20,590	29,890	44,253	
RAF	13,060		19,380		35,040
OEUS			31,000		
PEC			25,489		

Source: Ibid., p. 26.

UTILITY ELECTRIC POWER GENERATION[1]

[Billions of kilowatt hours]

	1970	1975	1980	1985	1990	2000
NPS	1,484	2,024	2,693			
RAF	1,287		2,084		3,044	4,467
N.F. & E.S			2,700			
CNP			2,700			
CGAEM	1,448	1,995	2,581	3,363		
PEC			2,739			
EUS			3,086			
EMUS			2,739			
PCCP			2,641			5,874

[1] Ooes not include industrial self generation. NPS estimates this at 127 in 1980 for total generation of 2,820.

Source: Ibid., p. 26.

FOSSIL FUELS FOR THE ELECTRICITY INDUSTRY

According to the most recent information from the Federal Power Commission,[1] the three principal fuels used in the production of steam-electric power, are coal, natural gas, and residual fuel oil. Coal is the prime fuel in many parts of the Nation. More and more western coal is burned each year from Arizona and New Mexico northward to North Dakota and Montana. Imported waterborne residual fuel oil is becoming an increasingly important fuel along the Atlantic coast from Maine to Florida. In 1968 the use of oil in this coastal area increased quite substantially. Both natural gas and residual fuel oil are burned by the Pacific coast plants. Natural gas is the prime fuel in the southwestern and south central producing areas. It is burned as a supplemental fuel when available at many of the plants near or on the route of the large, natural gas pipelines throughout most of the Nation. It is usually available during the summer months when there is little or no home heating load on the pipelines.

During the decade prior to 1967, approximately 66 percent of the total annual fossil-fueled steam-electric power generation was by coal, about 26 percent by natural gas, and the remaining 8 percent by residual oil. In 1967 coal-fired generation decreased to 64 percent of the total, natural gas-fired generation was 27 percent, and oil-fired generation was 9 percent. In 1968 the ratios were 61 percent, 29 percent, and 10 percent, respectively.

The weighted average fossil fuel costs, "as burned," for electric utility steam-electric generation for 1960 through 1968 are shown in table 10.

Fossil fuels burned annually for electric power production by electric utilities in the 48 contiguous States from 1960 through 1968 is given in table 11.

TABLE 10.—WEIGHTED AVERAGE FOSSIL FUEL COSTS FOR ELECTRICITY GENERATION, 1960–68

[Cents per million B.t.u. (as burned)]

	1960	1961	1962	1963	1964	1965	1966	1967	1968
Coal	26.0	25.8	25.6	25.0	24.5	24.4	24.7	25.2	25.5
Gas	[1] 23.8	25.1	26.4	25.5	25.4	25.0	25.0	24.7	25.1
Oil	34.5	35.4	34.5	33.5	32.7	33.1	32.4	32.2	32.8
Weighted average	[1] 26.2	26.7	26.5	25.8	25.3	25.2	25.4	25.7	26.1

[1] Revised (1965).

Source: U.S. Federal Power Commission. "Steam-electric plant construction cost and annual production expenses." op. cit., p. xvi.

[1] U.S. Federal Power Commission. "Steam-Electric Plant Construction Cost and Annual Production Expenses: Twenty-first Annual Supplement—1968." FPC report No. S-199, pp. xvi-xvii.

TABLE 11.—CONSUMPTION OF FOSSIL FUELS, 1960–68

Year	Coal, million tons	Gas, billion cubic feet	Oil, million barrels	Total, million tons coal equivalent
1960	176.6	1,724.5	85.3	266.4
1961	182.1	1,825.1	85.7	276.4
1962	193.2	1,966.0	85.8	293.6
1963	211.2	2,142.9	89.3	320.3
1964	225.3	2,321.3	96.7	344.4
1965	244.9	2,316.2	110.5	367.4
1966	266.4	2,608.8	140.9	418.7
1967	[1] 274.1	[1] 2,741.9	150.0	[1] 437.0
1968	[2] 296.8	[2] 3,138.3	[2] 182.1	[2] 484.3

[1] Revised.
[2] Preliminary.

Source: U.S. Federal Power Commission. "Steam-electric plant construction cost and annual production expenses." Twenty-first annual supplement—1968. 1970, p. xvii.

Total fuel consumption in 1968 was approximately 10 percent greater than in 1967.

Coal is inherently the most efficient of the three fossil-fuels used for power production purposes. A good grade of coal properly fired in a well-maintained boiler will produce more useful heat energy than an equivalent amount of natural gas or fuel oil. This is because coal contains less hydrogen than natural gas or oil. In the combustion process, the hydrogen in the fuel is converted to water and the latent heat of the water vapor resulting from the burning of the hydrogen is lost as useful work. Therefore, there are two values for a given fuel, the higher heating value (HHV) which includes the energy in the hydrogen, and the lower heating value (LHV) which excludes this energy. Generally speaking fuel prices are compared on a B.t.u. content basis using higher heating values. The higher heating values of fossil fuels are the U.S. standard in determining thermal efficiency or heat rate in the production of steam-electric power.

THE COMPETITIVE SITUATION OF FOSSIL AND NUCLEAR FUELS—BY REGION

The following general appraisal by the Federal Power Commission of the competitive positions of nuclear and fossil fuels by principal regions of the United States was presented to the Joint Committee on Atomic Energy in November 1969.[1]

New England and Middle Atlantic States.—With the exception of central and western Pennsylvania, where low-cost coal is abundantly available, the New England and Middle Atlantic States do not have access to low-priced coal. The competitive fuels in these areas are the imported low-sulfur-residual oils in locations with deepwater port facilities, and nuclear fuels.

East North Central States.—In these States coal has a marginal advantage over nuclear fuel. Most of the coal in this area, however, has a very high sulfur content and is not a competitor where air pollution regulations restrict the emissions of sulfur oxides.

West North Central States.—Both coal and natural gas compete effectively throughout most of this area, in part because of the relatively small average size of units which are required to accommodate

[1] Testimony of F. Stewart Brown, Federal Power Commission. In "Environmental Effects of Producing Power." Hearings before the Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, pt. 1, pp. 57-58.

the incremental energy demand in the region. Gas is expected to remain the dominant fuel in Kansas, and very low-cost, low-sulfur lignite will predominate in North Dakota. In Missouri, high-suflur coal has a significant advantage over nuclear fuel. The effectiveness of this price advantage can be expected to be diminished by air pollution control regulations.

South Atlantic States.—Although coal accounts for about 80 percent of the thermal generation (the use of residual fuel oil is significant only in Florida) its competitive position vis-a-vis nuclear fuel is weak except for West Virginia, which is the leading coal-producing State in the Nation. In this State coal will continue to be the principal fuel for electric power generation.

East South Central States.—Low-cost coal will continue to be highly competitive with nuclear fuel in Alabama, Kentucky, and Tennessee. Natural gas will prevail in Mississippi.

West South Central States.—Practically all the thermal electric power in this area is generated with natural gas. This region, including its offshore areas, is the origin of 80 percent of the Nation's current consumption of natural gas. Gas will continue to be the principal source of primary energy for electric power generation in the foreseeable future.

Mountain States.—The Mountain States are well endowed with low-cost, low-sulfur coal and this fuel will remain the dominant fuel in the electric utility market of the area. In addition, significant quantities of natural gas will continue to be used in Arizona, Nevada, and New Mexico.

Pacific States.—Although plans are underway for the use of coal for electric power generation in this region, to date, more than four-fifths of thermal electric generation is produced with natural gas, and the remainder with residual fuel oil. The cost of fossil fuels in the Pacific States, however, is generally high, and nuclear fuels should be able to compete effectively in the area, assuming that suitable sites for nuclear generation can be established.

In summary, it appears to the Federal Power Commission that nuclear generation will be competitive with other fuels during the next two decades in the New England States; in the Middle Atlantic States except Pennsylvania; throughout most of the South Atlantic States except for West Virginia; in parts of East Central States as they are subjected to more stringent regulations on the emission of sulfur oxides; and in all of the Pacific Coast States.

COAL FOR ELECTRICITY

The United States is well endowed with coal resources. Coal is extensively used in power generation, accounting for more than 60 percent of present thermal electric energy production. During much of the 1950's and the first half of the 1960's, labor productivity and the technology of mining and transportation advanced rapidly, resulting in a declining delivered price of coal to ultimate consumers. In the past several years, however, a number of developments have tended to exert upward pressure on the price of coal. Among these developments have been the general inflationary trends affecting the cost of labor and materials; laws requiring the restoration of mined lands; the need to prevent acid mine-water drainage into rivers,

lakes, and groundwater reservoir; air pollution regulations limiting the sulfur content of the coal used; and more stringent health and safety regulations for the operation of coal mines.

Adequacy of coal resources

If the projections shown in table 5 are approximately correct, demands on coal resources for generation of electricity would be increased from about 300 million tons per year at present to about 1 billion tons in the year 2000 A.D. It should first of all be noted as regards these materials that there is no near-term U.S. shortage of resources in nature. Coal is, so to speak, along with atomic power, our probable ace in the hole for the next several centuries. Total U.S. coal production in 1968 was 556,044,000 tons, very nearly the same as the 560,388,000 tons of 1950. In very large part this production was of the bituminous type, though small amounts of lignite and anthracite were included. About half of the 1967 total was used in generating electricity. An unofficial estimate indicated that about 310 million tons of coal were used by the utilities in 1969.[1] If by the year 2000, U.S. production possibly should be increased to 2 billion tons per year, with half of that total supplying the 1-billion-ton demand projected for generation of electricity (table 5), coal resources in the ground appear to be fully adequate for many decades. Capital, labor, and technology for economic removal of coal from its geologic formation appear more likely to constitute possible bottlenecks than the availability of the raw resource itself.

Parenthetically, it has been noted by Hubbert [2] that although coal has been mined for about 800 years, one-half of the coal produced during that period has been mined during the last 31 years. For the world, he finds that during a period from World War II to the present there has been a growth rate of 3.6 percent, with a doubling period of 20 years.

The Geological Survey estimate of 1967

It is true that coal resources are very largely underground and attempts are made from time to time at estimation, reevaluation and redefinition. The latest major official attempt was published in 1969.[3] In brief, it estimated coal resources of the United States at a total of 3,210 billion tons, of which about half may be considered recoverable. About half of the total was determined from mapping and exploration at depths of 0 to 3,000 feet of overburden (table 12).

[1] "The Journal of Commerce" (New York), Mar. 18, 1970, p. 10.

[2] See M. King Hubbert, "Energy Resources," ch. 8 in "Resources and Man—a Study and Recommendations," Committee on Resources and Man, National Academy of Sciences—National Research Council, W. H. Freeman & Co., San Francisco, 1969, p. 166.

[3] "Coal Resources of the United States, Jan. 1, 1967," Geological Survey Bulletin 1275, GPO, Washington, D.C., 1969, 116 pages.

TABLE 12.—TOTAL ESTIMATED REMAINING COAL RESOURCES OF THE UNITED STATES, JAN. 1, 1967

[In millions of short tons. Figures are for resources in the ground, about half of which may be considered recoverable. Includes beds of bituminous coal and anthracite 14 inches or more thick and beds of subbituminous coal and lignite 2.5 feet or more thick]

State	Overburden 0–3,000 ft thick: Resources determined by mapping and exploration (from table 1): Bituminous coal	Subbituminous coal	Lignite	Anthracite and semianthracite	Total	Overburden 0–3,000 ft thick: Estimated additional resources in unmapped and unexplored area [1]	Overburden 0–3,000 ft thick: Estimated total remaining resources in the ground	Overburden 3,000–6,000 foot thick, estimated resources in deeper structural basins [1]	Estimated total remaining resources in the ground, 0–6,000 feet overburden
Alabama	13,518	0	20	0	13,538	20,000	33,538	6,000	39,538
Alaska	19,415	110,674	(2)	(3)	130,089	130,000	260,089	5,000	265,089
Arkansas	1,640	0	350	430	2,420	4,000	6,420	0	6,420
Colorado	62,389	18,248	0	78	80,715	146,000	226,715	145,000	371,715
Georgia	18	0	0	0	18	60	78	0	78
Illinois	139,756	0	0	0	139,756	100,000	239,756	0	239,756
Indiana	34,779	0	0	0	34,779	22,000	56,779	0	56,779
Iowa	6,519	0	0	0	6,519	14,000	20,519	0	20,519
Kansas	18,686	0	0	0	18,686	4,000	22,686	0	22,686
Kentucky	65,952	0	(4)	0	65,952	52,000	117,952	0	117,952
Maryland	1,172	0	0	0	1,172	400	1,572	0	1,572
Michigan	205	0	0	0	205	500	705	0	705
Missouri	23,359	0	0	0	23,359	0	23,359	0	23,359
Montana	2,299	131,877	87,525	0	221,701	157,000	378,701	0	378,701
New Mexico	10,760	50,715	0	4	61,479	27,000	88,479	21,000	109,479
North Carolina	110	0	0	0	110	20	130	5	130
North Dakota	0	0	350,680	0	350,680	180,000	530,680	0	530,685
Ohio	41,864	0	0	0	41,864	2,000	43,864	0	43,864
Oklahoma	3,299	0	(4)	0	3,299	20,000	23,299	10,000	33,299
Oregon	48	284	0	0	332	100	432	0	432
Pennsylvania	57,533	0	0	12,117	69,650	[5] 10,000	79,650	0	79,650
South Dakota	0	0	2,031	0	2,031	1,000	3,031	0	3,031
Tennessee	2,652	0	0	0	2,652	2,000	4,652	0	4,652
Texas	6,048	0	6,878	0	12,926	14,000	26,926	0	26,926
Utah	32,100	150	0	0	32,250	48,000	80,250	35,000	115,250
Virginia	9,710	0	0	335	10,045	3,000	13,045	100	13,145
Washington	1,867	4,194	117	5	6,183	30,000	36,183	15,000	51,183
West Virginia	102,034	0	0	0	102,034	0	102,034	0	102,034
Wyoming	12,699	108,011	(2)	0	120,710	325,000	445,710	100,000	545,710
Other States	[6] 618	[7] 4,057	[8] 46	0	4,721	1,000	5,721	0	5,721
Total	671,049	428,210	447,647	12,969	1,559,875	1,313,080	2,872,955	337,105	3,210,060

[1] Estimates by H. M. Belkman (Washington), H. L. Berryhill, Jr. (Virginia and Wyoming), R. A. Brant (Ohio and North Dakota), W. C. Culbertson (Alabama), K. J. Englund (Kentucky), B. R. Haley (Arkansas), E. R. Landis (Colorado and Iowa), E. T. Luther (Tennessee), R. S. Mason (Oregon), F. C. Peterson (Kaiparowits Plateau, Utah), J. A. Simon (Illinois), J. V. A. Trumbull (Oklahoma), C. E. Wier (Indiana), and the author for the remaining States.

[2] Small resources and production of lignite included under subbituminous coal.

[3] Small resources of anthracite in the Bering River field believed to be too badly crushed and faulted to be economically recoverable. (See Barnes, 1951).

[4] Small resources of lignite in beds generally less than 30 inches thick.

[5] After Ashley (1944).

[6] Arizona, California, Idaho, Nebraska, and Nevada.

[7] Arizona, California, and Idaho.

[8] California, Idaho, Louisiana, Mississippi, and Nevada.

Source: "Coal Resources of the United States, Jan. 1, 1967," op. cit., pp. 12–13.

Recoverable coal resources

There are questions of what is and what is not minable at a given stage of technology and economics. Quantities probably ultimately recoverable in the United States at unspecified price levels have been estimated roughly in the neighborhood of 800 billion tons. Or, to take a more conservative approach:

> * * * A recent estimate of the Department of the Interior of 220 billion tons minable at or below present costs works out to over 400 years' supply at present rates of production, and more than 100 times present annual production of energy from all sources. Even if these figures are adjusted for future increases in energy demand, the estimated quantities would last far into the future. * * * [1]

Geographic location

But if the total coal resource is fully adequate for the present and for decades in the future, the geographical distribution is significantly unbalanced as may be noted in table 12, figure 2, and especially in figure 3. The principal highly developed coalfields at present are in three regions—the northern Appalachians, centering on Pennsylvania and the northern part of the West Virginia, a southern field mostly found in West Virginia and Virginia and a north-central field centering on Kentucky and Illinois (table 13). Though these areas now are and will continue to be much involved in production and the accompanying opportunities and problems which are associated with removal of coal resources from the earth, other large reserves in the Rocky Mountain region and the northern Great Plains also are likely to be increasingly involved.

TABLE 13.—COAL—PRODUCTION, BY STATES: 1941 TO 1967

[In thousands of short tons. Includes coal consumed at mines]

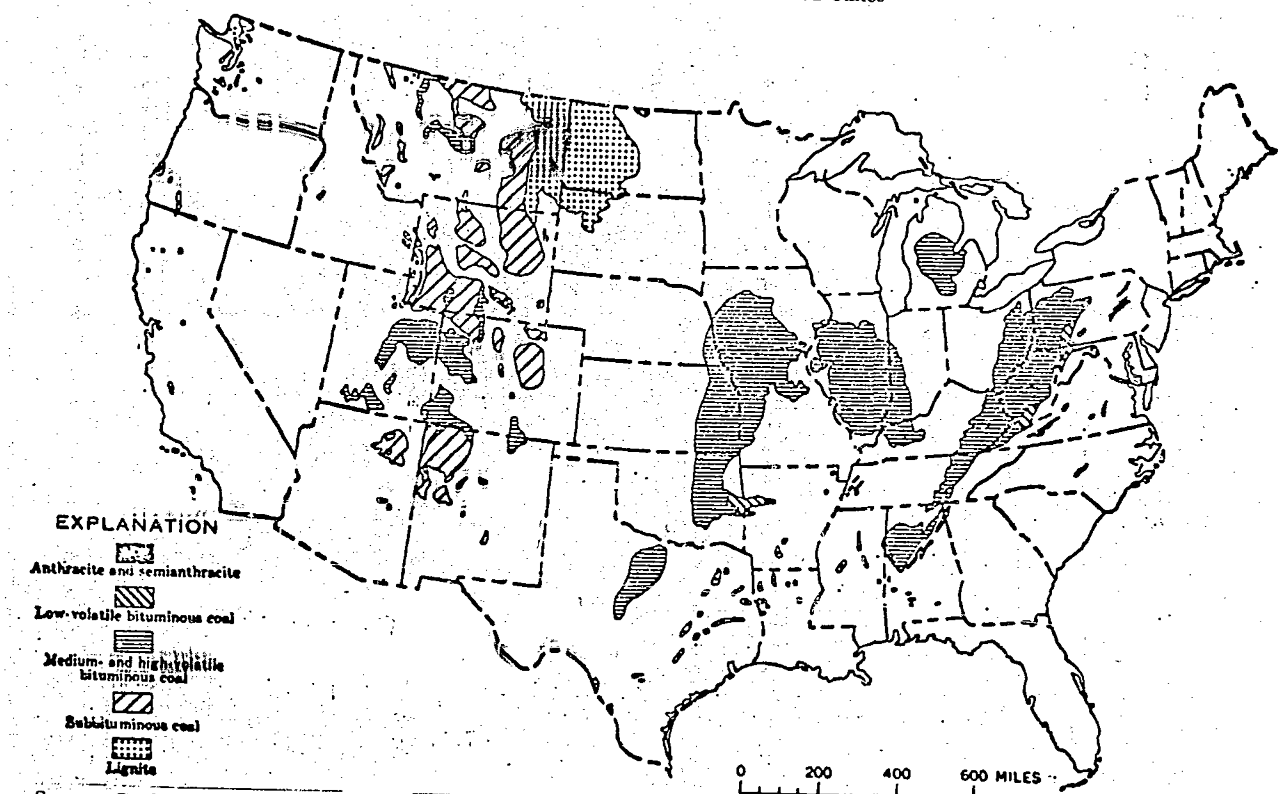
State	1941–45, average	1946–50, average	1951–55, average	1956–60, average	1961–65, average	1960	1965	1967
Total	636,037	595,972	496,725	469,288	473,559	434,329	526,954	564,882
Anthracite (Pa.)	59,195	52,323	33,898	22,975	16,931	18,817	14,866	12,256
Bituminous and lignite	576,842	543,649	462,827	446,313	456,628	415,512	512,088	552,626
Alabama	17,783	16,278	12,176	12,413	13,484	13,011	14,832	15,486
Colorado	7,830	5,360	3,554	3,394	3,978	3,607	4,790	5,439
Illinois	68,442	60,034	46,781	46,090	51,795	45,977	58,483	65,133
Indiana	25,216	21,500	16,232	15,659	15,311	15,538	15,565	18,772
Kentucky	64,020	74,791	66,426	69,038	75,621	66,847	85,766	100,294
Missouri	3,947	3,720	2,873	2,898	3,165	2,890	3,564	3,696
Ohio	32,190	35,458	35,647	35,379	35,968	33,957	39,390	46,014
Pennsylvania	138,876	120,441	89,680	[illegible]	71,261	65,425	80,308	79,412
Tennessee	7,184	5,520	5,923	7,086	6,010	5,931	5,865	6,832
Utah	6,012	6,613	6,025	5,642	4,706	4,955	4,992	4,175
Virginia	19,121	17,190	20,399	28,400	31,209	27,838	34,053	36,721
West Virginia	154,335	151,153	138,858	134,167	130,948	118,944	149,191	153,749
Wyoming	8,664	6,889	4,704	2,050	2,917	2,024	3,260	3,588
Other States	23,222	18,702	13,349	9,247	10,255	8,568	12,029	13,315

Source: Department of the Interior, Bureau of Mines, Minerals Yearbook. Statistical Abstract of the United States, 1969, p. 669.

[1] "U.S. Energy Policies—an Agenda for Research," Resources for the Future, Johns Hopkins Press, Baltimore, 1968, p. 71.

FIGURE 2

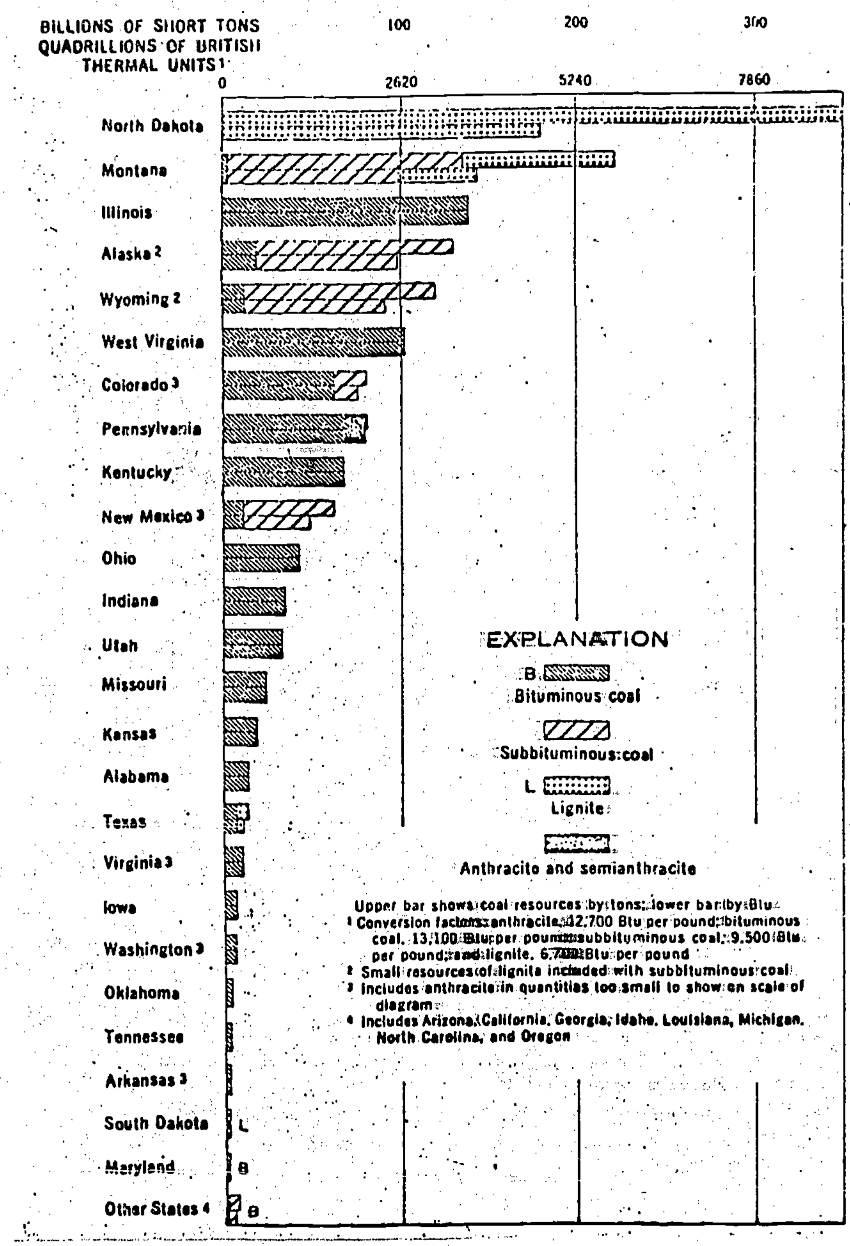
Coal fields of the conterminous United States



Source: Coal Resources of the United States, January 1, 1967, *op. cit.*, p. 5.

FIGURE 3

Remaining coal resources of the United States as determined by mapping and exploration, January 1, 1967, by States, according to tonnage and heat value



Source: "Coal Resources of the United States, January 1, 1967", *op. cit.*, page 20.

STRIP MINING OF COAL

In 1965 about 171,179,751 tons of coal were produced by "stripping," a form of mining which consists of removing the overburden so as to expose the coal horizon or vein to removal by comparatively easy mechanical techniques (table 14). The 12,256,000 tons of Pennsylvania anthracite coal produced in 1967, and valued at $96,160,000 is estimated to be only slightly involved in fueling electricity generation and will not here be discussed separately. Bituminous and lignite coals, of which 552,626,000 tons valued at $2,555,377,000 were mined in 1967, are directly involved. Moreover, these types provide very substantial reserves which, because of their quality and comparatively easy availability, are presumed likely to provide an increasing fraction of the larger tonnage needed in the future.

In 1963, 6,305 "establishments" were engaged in production of these coals, down from 6,940 in 1958 and 6,865 establishments in 1954. In 1968, the number of such mines had declined to 5,327 in which an average of about 131,000 men worked, producing 545,245,000 tons valued at $2,546,340,000.[1]

Of the total production of slightly less than 550,000,000 tons of U.S. bituminous and lignite coals mined in 1968, 185,836,000 tons were mined by 1,492 strip mines.[2] But information is not at hand as to how much coal produced by stripping, as distinguished from coals produced by underground operation, were used for generation of electricity.

Statistics at hand (table 15) indicate that less than one-fourth of U.S. coal mines are strip mines and that 46 percent of the strip mines are small and produced less than 25,000 tons in 1965, whereas about 127 of the largest mines each produced 250,000 or more tons in that year.

TABLE 14.—PRODUCTION OF COAL[1] BY STRIPPING IN THE UNITED STATES IN 1965, BY STATE

State	Short tons	State	Short tons
Alabama	4,808,844	North Dakota	2,730,594
Alaska	893,182	Ohio	26,634,829
Arkansas	151,593	Oklahoma	964,061
Colorado	1,270,129	Pennsylvania	29,706,420
Illinois	32,669,583	South Dakota	10,000
Indiana	13,210,102	Tennessee	2,066,777
Iowa	846,758	Virginia	3,080,742
Kansas	1,309,744	Washington	2,658
Kentucky	30,142,599	West Virginia	10,462,246
Maryland	736,841	Wyoming	3,135,955
Missouri	3,538,042		
Montana	300,459	Total	171,179,751
New Mexico	2,777,593		

[1] Includes anthracite, bituminous coal and lignite.

Source: "Surface Mining and Our Environment", U.S. Department of the Interior, 1967, p. 115.

[1] Minerals Yearbook 1968, vols. 1–11, Washington, D.C., 1969, p. 301.
[2] Ibid., pp. 344–345.

TABLE 15.—NUMBER OF STRIP PITS IN THE UNITED STATES REPORTING PRODUCTION OF BITUMINOUS COAL AND LIGNITE IN 1965, BY TONNAGE CATEGORY AND STATE

State	500,000 tons and over		250,000–500,000 tons		100,000–250,000 tons		50,000–100,000 tons		25,000–50,000 tons		Less than 25,000 tons		Total	
	Mines	Production (thousand net tons)	Mines	Production (thousand net tons)	Mines	Production (thousand net tons)	Mines	Production (thousand net tons)	Mines	Production (thousand net tons)	Mines	Production (thousand net tons)	Mines	Production (thousand net tons)
Alabama	2	1,085	2	521	12	1,812	10	746	13	455	19	190	58	4,809
Alaska			1	435	2	454					1	4	4	893
Arkansas							1	87	1	41	2	23	4	181
Colorado	1	553	1	393	1	224	1	67			3	33	7	1,270
Illinois	23	28,783	8	3,083	3	412	3	182	4	129	8	80	49	32,669
Indiana	11	10,846	5	1,940			2	132	5	172	18	120	41	13,210
Iowa					3	417	3	204	4	146	9	80	19	847
Kansas	1	842	1	261	1	181					3	26	6	1,310
Kentucky	14	23,622	6	2,202	14	2,288	12	867	21	704	49	460	116	30,143
Maryland					1	203	1	73	7	235	26	226	35	737
Missouri	3	2,888	1	442			2	112	2	61	5	35	13	3,538
Montana			1	298							2	2	3	300
New Mexico	1	2,398	1	369							1	11	3	2,778
North Dakota	1	1,073	2	685	4	646	2	149	1	37	18	141	28	2,731
Ohio	12	12,923	8	2,681	32	4,704	50	3,407	45	1,605	117	1,045	264	26,365
Oklahoma			1	296	2	380	3	208	2	62	3	18	11	964
Pennsylvania	1	1,096	7	2,353	30	3,974	131	8,635	123	4,652	289	3,057	581	23,767
South Dakota											1	10	1	10
Tennessee					6	896	11	693	7	264	17	214	41	2,067
Virginia			3	971	5	685	10	767	15	508	23	150	56	3,081
Washington											1	3	1	3
West Virginia	1	639	3	1,218	27	4,280	30	2,195	32	1,088	98	1,042	191	10,462
Wyoming	1	1,249	4	1,621	1	182	1	64			2	20	9	3,136
Total	72	87,997	55	19,769	144	21,738	273	18,588	282	10,159	715	6,990	1,541	165,251
Percent of total	4.7	53.3	3.6	12.0	9.3	13.2	17.7	11.2	18.3	6.1	46.4	4.2	100.0	100.0

Source: "Surface Mining and Our Environment," op. cit. p. 114.

Strip-mining technology

The yearbook describes the technology for strip mining in 1967 as follows:

> Emphasis in surface mining continued to be on large-capacity earth-moving equipment. While no new marks were set in the maximum size of shovels used in overburden removal, the upper limit in sizes of draglines used for this purpose continued to rise. A 130-cubic-yard dragline of U.S. manufacture was placed in operation in Australia, surpassing the previous limit of 85 cubic yards. The beginning of construction on a 145-cubic-yard model in Indiana and a 220-cubic-yard model in Ohio portends new records in the capacity of earthmoving equipment. The new 220-cubic-yard dragline, with a 315-foot boom and a total weight of 27 million pounds, is scheduled for completion in 1968. Known as the "Big Muskie," this behemoth will remove 325 tons of overburden in one pass. Built as a part of a $40 million expansion program, the shovel will uncover coal that will be transported by two 1,500-ton-capacity trains shuttling over an electric railway system between the mine and an electric power generating plant. Although no coal-hauling trucks larger than the 240-ton-capacity unit announced in 1965 were built in 1967, haulage units in the 100- to 120-ton-capacity range are being selected for new surface mines and to replace smaller sized haulage units at existing mines.[1]

Strip mining will increase

It would appear to be a safe assumption that if use of coal resources in generation of electricity is to be increased by a factor of 4 by year 2000, a very substantial part of the demand surely will be supplied by the stripping method of mining. It is probable that coal fields involved will in some degree shift in ways which are not now easy to foresee; with a rapidly growing population, new population and industrial centers may be involved. Also transportation of coal by pipeline may prove feasible and long distance transmission of electricity almost certainly will be involved. In spite of these uncertainties, one can reasonably anticipate increased future emphasis on the now largely underdeveloped coal resources of the western half of the United States, especially those of the Rocky Mountain area and the lignite deposits of the Northern Plains and even more particularly those suited to strip mining (table 16).

Adequacy of production

Though coal resources are so abundant that coal as a raw material is not likely to cause any energy gap which may develop by year 2000, problems nevertheless may arise in production of the much larger amounts which apparently are to be needed.

[1] Op. cit., p. 333.

TABLE 16.—ESTIMATED ORIGINAL RESOURCES OF STRIPPING COAL IN THE UNITED STATES IN BEDS GENERALLY LESS THAN 100 FEET BELOW THE SURFACE

[Figures are for resources in the ground, of which about 80 percent may be considered recoverable]

State	Millions of short tons	State	Millions of short tons
Alabama	800	North Dakota	50,000
Alaska	2,000	Ohio	5,000
Arizona	100	Oklahoma	500
Arkansas	263	Pennsylvania	8,000
Colorado	1,200	South Dakota	400
Illinois	[1] 23,000	Tennessee	200
Indiana	3,524	Texas	3,282
Iowa	600	Utah	300
Kansas	600	Virginia	1,000
Kentucky	6,000	Washington	100
Maryland	100	West Virginia	6,000
Missouri	1,000	Wyoming	10,000
Montana	15,000		
New Mexico	1,000	Total	139,969

[1] Overburden 0–150 ft.

Source: "Coal Resources of the United States, Jan. 1, 1967," op. cit., p. 57.

An important factor contributing to availability of coal at competitive prices is the extent to which new productive capacity is added to the coal industry. Without question, considerable capital investment will be required in the future if the demands for coal in the production of electric energy are to be met. This problem has two aspects, one related to the sheer magnitude of the future gross tonnages to meet the power industry's demands, and the other related to the growing amounts of coal required to supply specific powerplant projects.

Recently a serious coal supply problem has developed affecting all coal users, including the electric power industry which consumes more than one-half of the Nation's coal output. During the first 9 months of 1969, as compared to the same period of the previous year, U.S. consumption of coal has increased by about 20 million tons. At the same time production of coal at the mines has declined by about 25 million tons. This has resulted in a considerable drain on coal stockpiles of both the producers and the consumers. An FPC staff study prepared early in October of 1969 showed that coal stocks of many coal burning electric utilities have become seriously depleted. Some plants have as little as 15 days supply, in contrast to a desirable 60 to 90 day supply.

The East Central Regional Advisory Committee of the FPC points out that very large generating plants mean correspondingly large coal commitments and production rates not now available. The Committee said late in December 1969 that:

> The trend toward increased size of fossil-fired generating units and plants in order to achieve economies of scale, and the need to utilize fully the available plantsites, means large coal commitments. For example, a generating plant with an aggregate capacity of 3,000 Mw., which can be considered reasonable in the future, will require an annual coal supply of approximately 7.5 million tons. For a useful life for each of its units of 30 years, this means an overall guaranteed supply of about 200 million tons. Such large plants in many cases must utilize unit trains and other large-quantity coal movements and they cannot be economically sup-

plied from a large number of scattered mines. Relatively few coal mines in the country today have a productive capacity in excess of 5 million tons a year. As a matter of fact, only five bituminous coal mines produced 5 million tons or more in 1967, and only six additional mines produced over 3 million tons annually.[1]

The public press during the recent period has called attention to sharply lower coal stocks on hand, especially those held by utilities and steelmakers. Some are reported to have only 10 percent of stocks normally carried and even these, as in the case of the TVA, may have an unsatisfactory location.[2]

Among the causes which have contributed to this situation are the shortage of labor in underground mines and the shortage of railroad cars for coal transportation. The labor force in coal mining has in recent decades been overabundant; that may not be the case in the years ahead. It is reported that few sons of miners wish to follow the occupation of their fathers. Also, with greatly increased mechanization, the skills needed are rather different and more specialized than was formerly the case. This, in turn, may put additional emphasis on those particular coal resources susceptible to economic stripping, which is more capital intensive, less labor demanding. In turn, the emphasis on stripping may accelerate certain resulting environmental problems, which, though not new, have recently received new attention.

ENVIRONMENTAL EFFECTS OF STRIP MINING

The visible insult to the landscape of unrestored strip mines needs no further description here. The desolation thereby produced is well known to the public. Unreclaimed strip mines also may adversely affect the more remote surroundings. In areas of considerable land slope, stripped overburden materials in larger and small particles as well as those dissolved in water are likely to move down slope and downstream to the detriment of valleys, streams, and their fish. Strip mine wastes may clutter stream channels. The dissolved materials may reduce water quality for human and industrial use; and in some instances of intense erosion, valuable agricultural lands on the flood plains below may be greatly damaged by debris deposited.

Two other undesirable effects of strip mining are the drainage of acid mine wastes into streams and the burning of abandoned mines and waste or culm piles.

With regard to "acid" drainage aspects, as related to the mined area, as well as to possible later environmental pollution resulting from the combustion of the coal, it may be noted in table 17 that a large fraction of coal reserves are of low sulfur content, especially the lignite and subbituminous coals which largely remain to be developed.

[1] "Electric Power in the East Central Region 1970-1980-1990," a report to the Federal Power Commission prepared by the East Central Regional Advisory Committee, December 1969, p. III-10.

[2] Thomas L. Ehrich, "Supply-Demand Paradox—Coal Industry's new Vigor Is Being Sapped: Output Pinch Threatens Electricity Levels," Wall Street Journal, Mar. 11, 1970, p. 38.

TABLE 17.—ESTIMATED REMAINING COAL RESERVES OF THE UNITED STATES, BY RANK, SULFUR CONTENT, AND STATE, ON JAN. 1, 1965

[10^6 short tons [1]]

Coal rank and State	Sulfur content, percent									Total
	0.7 or less	0.8 to 1.0	1.1 to 1.5	1.6 to 2.0	2.1 to 2.5	2.6 to 3.0	3.1 to 3.5	3.5 to 4.0	Over 4.0	
Bituminous coal:										
Alabama	889.2	1,189.3	5,421.7	5,182.8	458.8	417.8			18.6	13,577.8
Alaska	20,287.4	1,100.0								21,387.4
Arkansas			1,128.4	293.1	154.0		40.3			1,615.8
Colorado	25,178.3	37,237.2								62,415.5
Georgia		76.0								76.0
Illinois [2,3]			1,808.0		1,139.5	17,871.9	36,264.0	62,130.0	20,542.6	139,756.0
Indiana	197.5	173.0	3,645.2	4,248.8	3,543.3	4,110.5	10,872.8	5,105.9	2,944.0	34,841.1
Iowa							117.1		6,405.4	6,522.5
Kansas			519.9	519.7	1,038.7	2,070.6	4,148.0	8,287.3	4,153.8	20,738.0
Kentucky:										
West			1,119.6	162.0	336.3	3,793.6	12,759.3	13,643.3	5,081.3	36,895.4
East	13,639.9	8,491.9	2,286.8	1,658.8	1,158.3	2,154.4	24.7			29,414.8
Maryland				124.6	191.8	208.2	378.6	56.4	220.4	1,180.0
Michigan								205.0		205.0
Missouri							6,456.7	20,669.2	51,634.1	78,760.0
Montana	51.2	218.2	205.0	397.2	400.0	175.0	40.0	27.0	591.0	2,104.6
New Mexico	5,212.0	5,474.0								10,686.0
North Carolina						110.0				110.0
Ohio		611.0	369.0	2,110.2	2,750.4	7,810.5	9,785.3	10,148.2	18,439.4	42,024.0
Oklahoma	250.6	772.2	825.0	368.1			577.2	19.1	490.6	3,302.8
Oregon		14.0								14.0
Pennsylvania	44.0	1,154.4	7,624.4	12,424.9	19,689.5	9,995.6	5,287.6	1,150.5	580.6	57,951.5
Tennessee	3.3	160.9	715.9	258.7	178.2	190.5	219.7	43.8	6.25	1,839.5
Texas					7,978.0					7,978.0
Utah	8,551.4	13,584.0		1,524.9					3,997.7	27,658.0
Virginia	1,981.5	6,077.5	1,637.1		123.9					9,820.0
Washington	898.9	672.1								1,571.0
West Virginia	20,761.0	26,710.6	21,819.7	13,290.6	8,496.1	2,491.8	3,147.4	5,949.2		102,666.4
Wyoming	6,222.2	6,596.6							1.1	12,819.9
Other States		616.0								616.0
Total	104,168.4	110,928.9	49,125.7	42,564.4	47,636.9	51,400.0	90,113.7	127,434.9	105,169.1	728,547.0
Percent of total	14.3	15.2	6.7	5.8	6.5	7.0	12.4	17.5	14.4	100.0

See footnotes at end of table, p. 44.

TABLE 17.—ESTIMATED REMAINING COAL RESERVES OF THE UNITED STATES, BY RANK, SULFUR CONTENT, AND STATE, ON JAN. 1. 1965—Continued

Coal rank and State	Sulfur content, percent									
	0.7 or less	0.8 to 1.0	1.1 to 1.5	1.6 to 2.0	2.1 to 2.5	2.6 to 3.0	3.1 to 3.5	3.5 to 4.0	Over 4.0	Total
Subbituminous coal:										
Alaska	71,115.6									71,115.6
Colorado	13,320.8	4,908.7								18,229.5
Montana	94,084.4	36,728.0	0.5	1,303.7						132,116.6
New Mexico	38,735.0	12,000.0								50,735.0
Oregon	87.0	87.0								174.0
Utah			150.0							150.0
Washington	3,693.8	500.0								4,193.8
Wyoming	35,579.7	72,315.6							8.6	107,903.9
Other States		4,047.0								4,047.0
Total	256,616.3	130,586.3	150.5	1,303.7					8.6	388,665.4
Percent of total	66.0	33.6	.1	.3						100.0
Lignite:										
Alabama			20.0							20.0
Arkansas	280.0	70.0								350.0
Montana	60,214.5	24,141.6	2,660.9			464.7				87,481.7
North Dakota	284,129.1	34,987.3	31,581.6							350,698.0
South Dakota		2,031.0								2,031.0
Texas			6,902.0							6,902.0
Washington		116.6								116.6
Other States		42.0								42.0
Total	344,623.6	61,388.5	41,164.5			464.7				447,641.3
Percent of total	77.0	13.7	9.2			.1				100.0
Alaska	2,101.0									2,101.0
Arkansas				145.5	286.3					431.8
Colorado		90.0								90.0
New Mexico		6.0								6.0
Pennsylvania	12,211.0									12,211.0
Virginia	335.0									335.0
Washington	5.0									5.0
Total	14,652.0	96.0		145.5	286.3					15,179.8
Percent of total	96.5	.6		.9	2.0					100.0
Grand total	720,060.3	302,999.7	90,440.7	44,013.6	47,923.2	51,864.7	90,118.7	127,434.9	105,177.7	1,580,033.5
Percent of total	45.6	19.2	5.7	2.8	3.0	3.3	5.7	8.0	6.7	100.0

[1] Coal in seams at least 14 inches thick and less than 3,000 feet deep in explored areas. Approximately one-half of these reserves are considered recoverable.
[2] See reference 17 for modification of low-sulfur coal reserves for Illinois.
[3] Illinois data are for 1966.

Source: Environmental Effects of Producing Electric Power, Hearings, Joint Committee on Atomic Energy, 91st Cong., first session, pt. 1, October–November 1969.

The Bureau of Mines of the U.S. Department of the Interior has reported using thermal infrared data obtained by remote sensing to monitor coal mine fires and burning culm banks. A wide variety of airborne sensor data, plus space flight photography from Gemini and Apollo missions, are being used in a study to determine their applicability to problems of observing and correcting surface effects of mining activities.[1]

Extent of strip mining

A rather comprehensive survey of "surface mining" was published 1967,[2] by the Department of the Interior as called for the Appalachian Regional Development Act of 1965 (Public Law 89–4 205(c)). Information presented therein for 1965 and shown here in table 14 indicates that a very large part of the total coal recovery by strip mining was from only a few States in that year. At that time, of the 3,187,825 acres which had been disturbed by strip and surface niming for one product or another, more than one-third or 1,301,430 acres related to coal production. Pennsylvania, Ohio, West Virginia, Kentucky, Illinois, and Indiana were high among the States affected. The total of about 1,302,000 acres affected by strip mining for coal was rather evenly divided between the "area" type of stripping (637,000 acres), and the "contour" type (665,000 acres). About 95 percent of the coal land acreage stripped in 1964 was privately owned. Of total acreage which had been disturbed by strip and surface mining (not just coal acreage), about two-thirds (2,040,600 acres) in 1965 still required reclamation, whereas about one-third for one reason or another did not require reclamation.

Cost of reclaiming strip mines

Reclaiming of coal land in 1964,[3] cost an average of $230 per acre for areas completely reclaimed and $149 per acre for areas partially reclaimed. These terms apparently are not fully defined. According to other information provided by that report[4] costs of reclamation even at levels up to as much as $800 per acre average not much more than 10 cents per ton of coal removed, though costs do vary rather widely from State to State. Though the cost does not appear high on a per-ton basis, the per-acre cost is large as compared with farmland values. Fortunately, table 15 would appear to indicate the likelihood that reclamation costs may be relatively low on a per-ton basis in lignite areas and in the Rocky Mountain area, partly because of thick beds and high tonnages per acre.

Limitations upon reclamation

It must not be assumed that in most areas, good farmland, once it has been exploited for its subsurface mineral treasure by stripping, can be quickly or ever fully returned again to its prior use for intensive crop farming. Grazing, forestry, even recreation, are more likely to be its new uses. There is little assurance, especially in the more humid areas, that drainage water from the stripped area will not be seriously reduced in quality by contamination with chemicals leached out of the newly exposed subsurface materials. In less humid areas the problem of reestablishing an adequate vegetative cover is reported to be more difficult.

[1] "Aeronautics and Space Report of the President," transmitted to the Congress, January 1970, Executive Office of the President, National Aeronautics and Space Council, Washington, D.C., 1970, p. 51.
[2] "Surface Mining and Our Environment," op. cit.
[3] Ibid., p. 113, table 5.
[4] Ibid., p. 114, table 7.

Regulation of strip mining

There has perhaps been too short a time since the 1967 report of the Interior Department and some resulting steps to provide preventative or remedial treatment for clear resolution of the environmental problems. It has been reported that the Department of the Interior in December 1969 undertook the review of current authority and the drafting of proposed legislation, if necessary, whereby Interior and Agriculture can assist local and State organizations in the restoration of past mined areas.[1] In a recent statement made in introducing a proposed mined land restoration and protection act of 1970, Senator Nelson has indicated that environmental regulation of strip mining is almost nonexistent at the Federal level, and at the State and local levels, spotty, at best.[2]

UNDERGROUND MINING

Environmental effects

Past experience with underground coal mining suggests that alternative expansion in those techniques would also prove to be increasingly destructive of some environmental qualities. Even if it be granted that the coal tipple and other surface appurtenances, along with the generally dreary mine villages are no more offensive to many persons than some nonmining aspects of the environment, there remain generally unsolved problems of acid drainage and of long-burning culm banks.

On the other hand, old slag heaps have in some areas proven to be useful as a source of industrial material. And a few artistic individuals are known to regard the old pink-gray mounds looming against the skyline of the flattish Midwest as interesting and attractive. They have been compared favorably with the pyramids of Egypt. But that point of view is exceptional. Few persons appear to regard coal mining in any of its versions as contributing favorably to the quality of the environment. To press on to higher levels of production will almost inevitably involve increased "exploitation" of present coal mining areas, large development of some new areas, and greater conflict with an increasingly critical public.

OIL

Because so much oil is used for purposes other than the generation of electricity, it is appropriate to first examine the role of oil in total energy supplies.

Oil and total energy

Exploitation of petroleum resources as a source of extraneous energy is even more recent in human history than use of coal. Contribution of oil to the total energy supply was almost negligible until after 1900, but since then use has grown very rapidly in several ways, particularly in powering the internal combustion engine. Modern transportation on land and by air can hardly be imagined without the products of petroleum. Domestic production of crude petroleum has increased from 1,353 million barrels in 1940, to 1,974 million barrels in 1950, and 2,575 million barrels in 1960, to about 3,329 million barrels in 1968. World production has increased even more rapidly, with the U.S. proportion of the world total showing a decline from 63 percent in 1940

[1] Richard Harwood and Lawrence Stern, Washington Post, Feb. 4, 1970, p. A17.
[2] Senator Gaylord Nelson, statement on S. 3491, Congressional Record, Feb. 23, 1970, p. S2145.

to 25 percent in 1967. Though oil was the basic energy source of only about 7.8 percent of the electricity generated in 1968, that use nevertheless required about 187,923,000 barrels in that year, against only 16,325,000 barrels in 1940 and 85,340,000 barrels in 1960. If the 1968 figure of nearly 188 million barrels is to rise to 800 million barrels by year 2000 as estimated in table 5 above, demand on petroleum resources for this purpose would be very substantially increased. Oil's contribution to total energy resources utilized then in generating electricity should decline to about 5 percent. The components presently used for this purpose mostly fall in the heavy residual fuel oil category, a byproduct of the refining industry; it appears unlikely that demands for other major products of the refining industry will be eased enough in the years ahead to favor an increase in the residual fraction.

In table 7 are shown several estimates published since 1962 of the probable U.S. requirements in 1980 for total energy, as well as for oil and gas. It may be noted that experts concede that values projected for future oil and gas consumption can be varied endlessly, depending on assumptions employed for energy growth rate and interfuel competition.

The estimates present a considerable range with consequent substantial differences in demand for capital investment. In general the more recent are higher; they indicate an overall probable demand of 16 to 18 million barrels per day with other recent estimates ranging as high as 20 million barrels per day in 1980.[1] A recent estimate for 1970 indicates 14,680,000 barrels per day required—a 4.8-percent gain over 1969. As projected, 1970 would be supplied by average production of 9,525,000 barrels per day of domestic crude, an increase of 3.3 percent over 1969, plus natural gas liquids amounting to about 1,683,000 barrels per day, an increase of nearly 7 percent over 1969. Imports would be sharply increased; crude would increase by 14.3 percent to 1,595,000 barrels per day, and products by 4.7 percent to 1,830,000 barrels per day.[2]

World supply situation

On a basis wider than the domestic, there is evidence that for the near future surplus rather than scarcity is probable. Commenting that most conditions suggest a fairly tough period ahead for all the oil giants when it comes to business outside America, the Economist said in 1968: "The problem is partly a matter of the abundance of oil. Production and consumption are fairly well balanced at the moment, rising at about 7½ percent a year, but both are outstripped by a 10-percent rise in the amount of newly discovered oil. At the present rate of consumption, proven reserves are now big enough to last until the year 2001. Some 63 percent of these reserves are located in the Middle East, 11 percent in North America, 10 percent in Communist areas."[3]

According to recently published research,[4] free world petroleum explorers have uncovered more than half (59 percent) of all existing giant fields since 1950. Of the known 71 giant fields, defined as those good for at least 1 billion barrels of ultimate recoverable reserves (past production plus remaining reserves) 21 were discovered in the 1950's

[1] Statement to New York Security Analysts by Robert O. Anderson, chairman of the board of the Atlantic Richfield Co., Congressional Record, Feb. 23, 1970, p. S2156.
[2] "Modest Gains Forecast for 1970," Oil and Gas Journal, Jan. 26, 1970, pp. 113-127.
[3] The Economist (London), Aug. 10, 1968, p. 48.
[4] Robert J. Burke and Frank J. Gardner, "The World's Monster Oil Fields, and How They Rank," Oil and Gas Journal, Jan. 13, 1969, pp. 43-49.

and at least another 21 have been found during the 1960's. Those 71 fields originally held about 360 billion barrels of such reserves; of that amount some 62.5 billion barrels have already been produced, leaving an estimated 297 billion barrels of recoverable reserves, or about 74 percent of the free world reserve.

Of the 71 fields, 38 are in the Middle East and only 18 in the Western Hemisphere, of which 11 are in North America. There are, of course, a good many known smaller fields, particularly in the United States. For example, if the cutoff size were set at an estimated ultimate recovery of 100 million barrels or more per field, the United States alone has 259 oil and 47 gas giants, which are indicated as now producing about 51 percent of the national output and holding 57 percent of the remaining reserve.

But for the free world, the six largest fields are indicated to contain more than 47 percent of total recoverable oil, and none of those six is in North America; five are in the Middle East and one in Venezuela. Not only are few of the North American entries anywhere near the top in size but for the most part they were discovered rather early and have been rather intensively developed. For example, of the U.S. monsters, East Texas, Wilmington, Yates, Kelly-Snyder, Midway-Sunset, and Huntington Beach were all discovered before 1950, one of them as early as 1901, and have yielded about half or more of their ultimate recoverable oil. Elk Hills is an exception; though discovered in 1920, the great bulk of its reserve is still in the ground. That also is the case of the two monster Canadian fields, Pembina, discovered in 1953, and Swan Hills, 1957.

The discovery in 1968 on Alaska's North Slope (Prudhoe Bay) is not included in the list of 71 monster fields, though respected experts have estimated that the structure could hold 5 to 10 billion barrels of recoverable oil. However, with few completed wells, the reserves are not yet regarded as proved. Moreover this is a relatively small part of the general area which will be explored.

Of some possible significance in the world supply situation are indications that the U.S.S.R. may have nearly completed its production of an excessive surplus of petroleum. In January 1969, the Soviet Union's petroleum minister, Valentin D. Shaskin, was reported as predicting that Russian oil exports would not continue to rise significantly because of growing domestic requirements.[1] As reported, in 1968, total crude oil production was 309 million metric tons, of which 57 million metric tons were exported in the form of crude oil and an additional 25 million tons as refined products, or roughly one-fourth of total production. Whether this situation will be notably changed by the recently announced new "north slope" Siberian field named Samotlar in the Ob River area is unclear. Recoverable reserves were estimated at 14 billion barrels.[2]

Not only the oil wells (table 18) but even more, U.S. production of petroleum shows heavy concentration in a few States, notably Texas, Lousiana, and California which in 1967 accounted for about 70 percent of the total (fig. 4 and table 19).

[1] New York Times, Jan. 11, 1969, pp. 39 and 47.
[2] New York Times, Mar. 28, 1970, pp. 1 and 40.

TABLE 18.—PRODUCING OIL WELLS IN THE UNITED STATES AND AVERAGE PRODUCTION PER WELL PER DAY, BY STATES

State	Producing oil wells 1966: Approximate number of producing oil wells, Dec. 31	1966: Average production per well per day (barrels)[1]	1967: Approximate number of producing oil wells, Dec. 31	1967: Average production per well per day (barrels)
Alabama	524	42.2	532	38.0
Alaska	72	609.9	94	961.1
Arizona	6	45.2	20	616.4
Arkansas	6,372	10.5	6,459	9.2
California	41,348	23.0	41,608	23.7
Colorado	2,371	42.6	1,730	45.3
Illinois	28,608	5.9	27,887	5.7
Indiana	5,300	5.5	[1] 4,831	5.5
Kansas	46,016	6.1	47,597	5.8
Kentucky	14,800	3.3	13,255	3.0
Louisiana:				
Gulf coast	16,804	104.4	16,867	117.1
Northern	14,259	10.4	13,803	10.7
Total	31,063	60.3	30,670	68.7
Michigan	4,141	9.6	4,004	9.2
Mississippi	2,549	59.8	2,557	61.3
Montana	3,507	26.5	3,390	27.8
Nebraska	1,511	24.3	1,430	24.9
New Mexico:				
Southeastern	14,981	19.9	15,210	20.9
Northwestern	1,523	18.0	1,535	19.9
Total	16,504	19.7	16,745	20.8
New York	[2] 11,832	.4	12,582	.4
North Dakota	2,017	37.2	2,063	34.0
Ohio	14,192	2.1	14,638	1.9
Oklahoma	80,583	7.6	80,970	7.8
Pennsylvania	[2] 50,645	.2	[2] 45,426	.3
South Dakota	29	23.0	28	20.0
Texas:[3]				
Gulf coast	19,255	27.8	18,925	31.0
East Texas field	16,843	7.0	16,328	8.6
West Texas	66,910	20.2	66,002	21.5
Panhandle	13,923	6.9	13,862	6.8
Other districts	79,377	9.9	76,884	10.4
Total	196,830	14.7	192,001	15.8
Utah	867	77.4	869	76.9
West Virginia	13,467	.8	12,989	.7
Wyoming	8,434	44.6	8,547	44.0
Other States:				
Florida	42	123.2	41	103.5
Missouri	150	1.8	146	1.4
Nevada	10	88.5	13	66.5
Tennessee	32	.6	33	.6
Virginia	2	.7	4	2.7
Total	236	26.1	237	22.4
Total United States	583,302	14.2	573,159	15.2

[1] Based on the average number of wells during the year.
[2] Compiled by Bureau of Mines, all other number of producing oil wells furnished by State agencies.
[3] Division of the Texas Railroad Commission.

Source: Minerals Yearbook 1967, GPO, Washington, D.C., 1968, vols. I-II, p. 863.

TABLE 19.—STATES' SHARE OF TOTAL U.S. CRUDE OIL OUTPUT, 1967 [1]

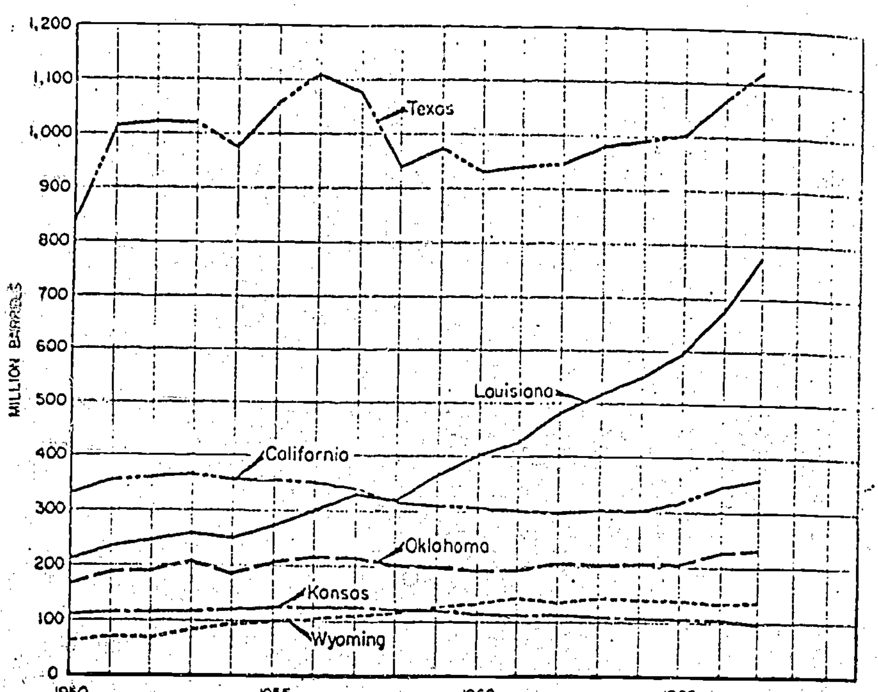
State	Share (percent)	State	Share (percent)
Alabama	0.23	Montana	1.09
Alaska	0.91	Nebraska	0.42
Arizona	0	Nevada	0
Arkansas	0.66	New Hampshire	0
California	11.17	New Jersey	0
Colorado	1.05	New Mexico	3.92
Connecticut	0	New York	0.06
Delaware	0	North Carolina	0
District of Columbia	0	North Dakota	0.79
Florida	0.05	Ohio	0.31
Georgia	0	Oklahoma	7.18
Hawaii	0	Oregon	0
Idaho	0	Pennsylvania	0.14
Illinois	1.84	Rhode Island	0
Indiana	0.31	South Carolina	0
Iowa	0	South Dakota	0
Kansas	3.08	Tennessee	0
Kentucky	0.48	Texas	34.83
Louisiana	24.09	Utah	0.75
Maine	0	Vermont	0
Maryland	0	Virginia	0
Massachusetts	0	Washington	0
Michigan	0.42	West Virginia	0.11
Minnesota	0	Wisconsin	0
Mississippi	1.78	Wyoming	4.24
Missouri	0		

[1] Does not sum to exactly 100 percent, because of rounding.

Source: "The Oil Import Question—A Report on the Relationship of Oil Imports to the National Security," Cabinet Task Force on Oil Import Control, GPO, February 1970, p. 28.

FIGURE 4

Production of crude petroleum in the United States, by principal producing States



Source: Minerals Yearbook, 1967, 1968, Vol. I-II, page 844.

Oil for electricity

Since the residual fuel oil burned in steam electric powerplants cannot be moved economically by pipeline over long distance, the use of oil for electric power generation is essentially limited to areas bordering low-cost water transportation or adjacent to petroleum refineries.

Slightly more than one-quarter of the total annual residual oil supply in 1968, was consumed by electric utilities. Domestic production of residual fuel oil has been steadily declining, but imports of this commodity have nearly doubled during the past decade. Unlike crude petroleum and refined products, imports of residual oil are not restricted by import controls, and its use for electric power generation has been growing rapidly.

The abundant worldwide supply of residual fuel oil at this time and the associated lowering in price have accelerated the increase in its use. Furthermore, technology for the removal of most of the sulfur contained in residual oil is available and the industry is investing considerable sums of money in oil hydrodesulfurization facilities. In the next several years the oil industry, worldwide, is likely to acquire a capacity to supply large quantities of residual fuel oil capable of meeting the most stringent sulfur content regulations for air pollution control.

The projected fourfold increase in demand on petroleum for generation of electricity by year 2000 apparently would be accompanied by a somewhat equivalent increase in the overall demand for petroleum. To meet the larger future demands for petroleum and its products whether total or only for generation of electricity, we must either find it in this country, import from foreign countries, or resort to the oil shales and other synthetic production, as from coal.

Exploration and reserves.—Unlike coal which may in some instances be scooped up from strata near the surface, petroleum is found and harvested by probing deep into the earth with wells. The well may prove to be "dry" or yield either petroleum or natural gas, or both. In other words, to a degree, oil and gas share a common domain and are sometimes referred to as the petroleum group of fossil fuels.

It is indicated that over 2 million wells have been drilled in the United States for oil and gas; and about 700,000 are currently producing, of which about 575,000 are "oil" wells. About 25,000 larger and (mostly) smaller oil and gas fields have been identified in 32 States. Nevertheless, because of the erratic manner in which accumulations of oil and gas occur underground, the problem of estimating the quantities of these resources still undiscovered by drilling in any given region is indeed difficult and subject to a wide range of possible interpretation.

For example, Hubbert [1] has recently noted:

> * * * How accurately are the undiscovered resources of oil and gas in the United States known? In this regard it may be mentioned that estimates published within the last 12 years of the ultimate production of crude oil in the United States, exclusive of Alaska, have a fourfold range from about 145 to 490 billion barrels. Corresponding estimates for natural gas have a threefold range from 850 to 2,650 trillion cubic feet.

[1] M. K. Hubbert, op. cit., p. 170.

In view of the wide range in these U.S. estimates, it may be noted that they are the work of experienced and reputable scientists proceeding on different but seemingly reasonable hypotheses and assumptions. All have been discussed and criticized. No attempt will be made here to examine in detail or to justify either low or high estimates, except to report that the high estimate [Zapp] concludes that it cannot be safely assumed that even the 20-percent mark has been reached in exploration for petroleum in the United States, excluding Alaska and excluding rocks deeper than 20,000 feet. On the other hand a comparatively low estimate [Hubbert], based essentially on rate of exploration activity, would appear to indicate that by year 2000 the United States and adjacent continental shelves will have run through four-fifths of the complete cycle of crude oil production.

It may be noted that a comprehensive staff study in 1962 for the Senate Interior and Insular Affairs Committee concluded in part:

> Attempting to assess the Nation's oil resources on information that is publicly available is as frustrating as chewing on a mouthful of mashed potatoes: There is nothing to get one's teeth into.
>
> * * * * * * *
>
> The subject of oil reserves and resources has received exhaustive and spirited professional attention for many years. The subject is highly speculative, but it seems safe to conclude that something of the magnitude of 400 billion barrels are recoverable from oil pools in the United States. * * *[1]

At least two situations lend basic support to the assumption that large domestic sources remain to be discovered and developed. One is the announcement that Alaska's new North Slope oil field is potentially one of the world's largest—containing possibly some 5 to 10 billion barrels of recoverable oil.[2]

Another is the challenge of a possible big Atlantic coast oil potential. Though largely unexplored and almost undrilled, the sediments beneath the coastal plain and the offshore shelf are indicated as comparing favorably in volume, age, and general appearance with similar formations in the Gulf basin which have proven substantially productive.[3] Both Alaska and the Atlantic coastal plain will require stringent environmental protection regulations as the exploration for and recovery of petroleum deposits proceeds.

A possible third encouraging aspect of the current situation is a new attempt to get a better idea of where and how much domestic oil and gas remains to be found. The Oil and Gas Journal of July 22, 1968 (newsletter) reported:

> National Petroleum Council's shooting for May 1, 1969, wrapup of first stage of in-depth study of possible future petroleum provinces in the U.S. * * * Nothing like it has been done since 1951. NPC Committee has divided country into 11 regions and picked a geologist in each to ramrod effort. Manuscripts from each region are due next May, and NPC will weld them into overall report.

It is not the nearby situation which causes most concern. The approximate 573,159 wells reported at the end of 1967 as producing petroleum provided in 1968 something like 3,329 million barrels[4]

[1] "National Fuels and Energy Study (Draft of May 18, 1962)," staff study to the Committee on Interior and Insular Affairs, U.S. Senate, 87th Cong., 2d sess., Committee Print No. 3. Washington, D.C., 1962, p. 52.

[2] Oil and Gas Journal, July 22, 1968, pp. 34–35.

[3] Ibid., pp. 46–47.

[4] Statistical Abstract, 1969, p. 670.

(table 18). In fact, the United States has considerable "shut-in" capacity and on occasion has been able to increase production by as much as 1 million barrels daily.

The decline in U.S. drilling for oil.—The petroleum-producing industry is by its very nature a long-term undertaking. From the time exploratory efforts are first begun until reserves are developed some 5 years or more may normally be required.

Total wells drilled to completion in the United States for oil and/or gas reached a peak in 1956 of 58,160 wells involving a total footage of 234 million feet—an average of 4,022 feet per well. Of that total 16,207 were classed as "exploratory" by the American Association of Petroleum Geologists. In 1958 about 13,000 such exploratory wells were drilled. After early 1959 import of foreign crude oil was considerably restricted by mandatory quotas. Some thought this would add incentive for finding and developing new domestic reserves. Jensen, writing in 1967, commented that in the decade between 1956 and 1965, wildcat well completions declined by one-third and developmental drilling by one-fourth.[1] New reserves added annually scarcely equaled production and in some years were even less. Searching for reasons for the perverse trend he apparently agreed with a committee of the National Petroleum Council that the interior region of the United States had been "fished out"—that the only good quality domestic reserves remaining to be developed were offshore and on the periphery of the United States—in south Louisiana, parts of Texas, in California, and Alaska. Others have thought the decline in wildcatting due to lack of adequate incentives.

In any case only 9,466 such wells were completed in 1965. There was some increase in 1966 to 10,313 wells followed by a slump to 8,878 wells in 1967 and 8,879 in 1968. In the spring of 1969 a rise of about 20 cents per barrel in sale prices of crude oil was reported to have stimulated a number of U.S. independent petroleum producers to plan acceleration of their exploration and wildcatting activities, thus perhaps reversing a decade of retrenchment.[2]

In mid-1969 there were some indications that drilling was turning up after a long drop.[3] The revised forecast for the entire year called for 31,897 wells (excluding service wells and stratigraphic and core tests). This would have been a 4-percent gain over the 1968 year total, or 1,316 wells. It was estimated that wildcatting would have a 9-percent increase over 1968, and field-well drilling (development) would show a 2-percent gain. Total footage would gain 5 percent.

Exploratory drilling did increase moderately in 1969; some 9,121 wildcat wells resulted in 1905 discoveries, of which 1,054 were oil and 851 gas. These totals include new field discoveries and new pay discoveries within existing fields.[4] Early indications were that drilling in 1970 would show a decline of about 5 percent, with plans calling for 30,085 wells as compared with 31,592 drilled last year. Drilling plans for 1970 called for 9,064 wildcats—off 4 percent, and 21,021 development wells, down 6 percent.[5]

[1] James E. Jensen, "Crude Oil: Capacity, Supply Schedule, and Imports Policy," Land Economics, vol. XLIII, No. 4, November 1967, pp. 385-392.
[2] Wall Street Journal, article by David Brand and Norman Pearlstine, Mar. 5, 1969, p. 34.
[3] Oil and Gas Journal, July 28, 1969, p. 136.
[4] Journal of Commerce, Jan. 26, 1970, p. 8A.
[5] Oil and Gas Journal, Jan. 26, 1970, p. 117.

In view of the very substantial decline in drilling, both wildcat and developmental since the 1950's, it might appear to be contradictory that proved crude oil reserves did not decline sharply in the 1960's (table 20). They were estimated at 30,613 million barrels at the end of 1968 as compared with 31,613 million barrels in 1960.

Present balance of reserves and demand.—In general, the domestic oil industry has managed to increase reserves and producing capacity as required to meet increases in demands. At the end of 1946 proved recoverable liquid petroleum reserves in the United States were estimated to be 24 billion barrels, or approximately 12 times the 1946 production. Over the following 17 years, 44 billion barrels were produced, or 20 billion barrels more than had been estimated as proved recoverable liquid petroleum reserves in 1946. Yet, proved reserves on January 1, 1964, had increased to 31 billion barrels and are not much below that level at present.

TABLE 20.—ESTIMATES OF PROVED CRUDE-OIL RESERVES IN THE UNITED STATES ON DEC. 31, 1967, BY STATES [1]

[Million barrels]

State	1963	1964	1965	1966	1967
Eastern States:					
Illinois	417	391	371	362	336
Indiana	63	61	57	48	47
Kentucky	100	118	108	101	94
Michigan	69	58	53	71	63
New York	18	14	12	10	15
Ohio	88	100	101	101	114
Pennsylvania	92	87	77	73	63
West Virginia	57	69	55	57	56
Total	904	888	834	823	788
Central and Southern States:					
Alabama	45	50	66	85	79
Arkansas	225	205	201	181	176
Kansas	841	797	752	726	625
Louisiana	5,089	5,162	5,246	5,408	5,455
Mississippi	385	357	360	374	357
Nebraska	84	71	71	57	63
New Mexico	1,011	947	895	1,025	926
North Dakota	389	377	395	321	299
Oklahoma	1,628	1,586	1,517	1,518	1,453
Texas [2]	14,573	14,300	14,303	14,077	14,494
Total	24,270	23,862	23,806	23,772	23,925
Mountain States:					
Colorado	368	346	327	344	340
Montana	271	252	274	282	308
Utah	220	219	197	213	201
Wyoming	1,254	1,204	1,169	1,073	1,044
Total	2,113	2,021	1,967	1,912	1,893
Pacific Coast States:					
Alaska	(3)	83	160	322	381
California [2]	3,600	4,125	4,567	4,608	4,369
Total [1]	3,600	4,208	4,727	4,930	4,750
Other States [4]	83	12	18	15	21
Total United States	30,970	30,991	31,352	31,452	31,377

[1] From reports of Committee of Petroleum Reserves, American Petroleum Institute. Includes crude oil that may be extracted by present methods from fields completely developed or sufficiently explored to permit reasonably accurate calculations. The change in reserves during any year represents total new discoveries, extensions, and revisions, minus production.

[2] Includes offshore reserves; the Dec. 31, 1967, total for Louisiana and Texas was 2,375.

[3] Included with "Other States."

[4] Includes Alabama, Alaska 1963 only, Arizona, Florida, Missouri, Nevada, South Dakota, Tennessee, and Virginia.

Source: Minerals Yearbook, 1967, op. cit., p. 858.

In part this results from the definition itself. The term proved reserves applied to crude oil is used to denote the amount of oil in known deposits which is estimated to be recoverable under current economic and operating conditions. Reserves, so defined, are probably on the conservative side.[1] In general they include only the producible content of the explored portions of reservoirs—an underground inventory, so to speak. As the reservoir is further explored substantial amounts may be added to the quantity proven.

Another point which may be helpful in understanding the situation is the improved recovery rate. The U.S. Department of the Interior has called attention to this factor as follows:

The crude oil recovery rate was estimated to be 30 percent at the end of 1965 and is believed to be increasing at an annual rate of 0.5 percent of total original oil in place. The bases for this increase are not well delineated, and there is no certainty that it can be continued at the current rate. On the assumption that it will be, however, the improvement of 7.5 percent in recovery rate to 37.5 percent by 1980 would yield an additional 29 billion barrels of economically recoverable reserves even if no new discoveries were made.[2]

That study, after making further points, which included the following:

The calculated trend of crude oil discoveries from 1920 through 1980 will result in discoveries of 72 billion barrels of oil in place between 1965 and 1980. On the basis of 37.5 percent recovery, these discoveries will yield 27 billion barrels of reserves.

When reserves acquired by discovery are added to those obtained through increased recovery, the resulting 56 billion barrels will be adequate to offset anticipated production and increase the reserve level by 4 billion barrels; *however*,

The calculated discovery rate is 4.8 billion barrels annually between 1965 and 1980. Discoveries actually reported since 1957, adjusted to compensate for partially developed fields since 1957, have averaged 3.2 billion barrels annually, approximately two-thirds the calculated rate. At the end of 1966 cumulative reported discoveries were seven billion barrels below the calculated trend line.

The departure of reported (adjusted) discoveries from the historic trend since 1957 coincides with large declines in activity indices normally identified with the discovery of oil: Geophysical crew months worked; exploratory drilling; and numbers of new oilfields found.

Concluded as follows:

It therefore appears that the discovery rate observed since 1957 will not be sufficient to offset withdrawals from proved reserves between 1965 and 1980 on the basis of anticipated recovery rates. Specifically, either the recovery rate must improve even faster than the 0.5 percent annual improvement projected, or discoveries must be increased above the levels that have prevailed since 1957.

Environmental effects of oil production

A serious and complex problem which confounds most discussion of petroleum availability in 1980 or even 2000 is that of pollution. The problem of oil pollution at the production stage comes mostly from "blowouts." It is a reasonable statement that the oil industry has long experienced and tried to prevent blowouts and that the record is much better than it used to be—the number of such events has decreased. The problem nevertheless has become increasingly serious in its implications respecting the environment. Earlier disasters were very largely on land and for the most part afflicted small local areas, so the damage was generally restricted and the situation promptly brought under control.

[1] "An Appraisal of the Petroleum Industry of the United States," U.S. Department of the Interior, January 1965, p. 13.

[2] "United States Petroleum Through 1980," U.S. Department of the Interior, GPO, Washington, 1968, p. vii.

Effects of oil operations at sea.—With major development of offshore drilling and large-scale production from the subsurface of the sea bed, the oil involved in a single disaster in some instances became much larger and control and remedial treatment much more difficult. Public awareness of the problem has increased greatly. Recently offshore wells, especially those near much-used beaches, wildlife refuges and commerical seafood resources have been seriously involved. Two major examples have been prominent—one, the *Santa Barbara Channel* case in California has been extremely difficult to contain. Still more recent is the case of the Chevron Oil Co. platform in the Gulf of Mexico near Louisiana and not many miles from shrimp and oyster beds valued at $100 million. Gas ignited and a blaze raged for about a month in February and March 1970 before the structure was dynamited in an unsuccessful first attempt to extinguish the blaze and cap the wells believed responsible for releasing under pressure something like 1,000 barrels of oil per day. Several wells provided oil for the fire and one was a major source of pollution. Secretary of the Interior Walter J. Hickel is reported to have said: "Compared to Santa Barbara, this is a disaster. There is more oil involved, more pollution, a wider area and it will take much longer and be much harder to clean up."

These major instances of production disaster and some lesser ones, plus major pollution of several coastal areas arising from ocean transportation of petroleum by tanker, notably the *Torrey Canyon* disaster off southwest England in 1967, and the *Arrow* incident off Chedabucto Bay, Nova Scotia, in February 1970 and other recent spills or dumping of oily bilge near the coast of Florida and that of Alaska have alarmed the public and created a multitude of lawsuits.

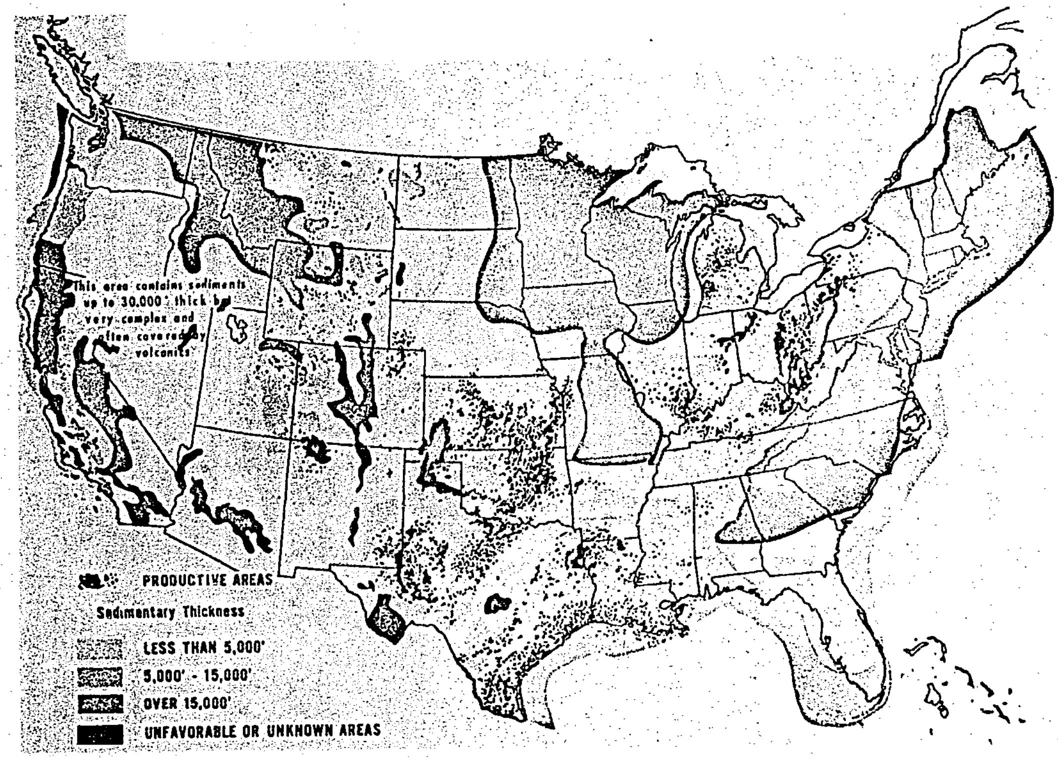
Effects of oil operations on land.—On land, it may be said that the environment is no longer cluttered by forests of closely spaced oil well derricks. Spacing orders now generally specify 40- and 80-acre units. There are in most States specifications for completing new wells and abandoning old ones, casing to prevent contamination of fresh water, proper disposal of produced water, whether salty or oily, to prevent pollution, and, of course, precautions to minimize the likelihood of blowouts or other accidents. Though quantitative information is not at hand, it is known that pollution and other local environmental damage does result in some instances, perhaps most strikingly in the case of some successful wildcat wells for which adequate preparation has not been made.

In most instances it would appear that environmental damage can be and is rather quickly contained on land.

With onland problems of production and transportation of petroleum sufficiently well in hand so that substantial pollution seldom occurs, the onland search for new petroleum reservoirs might for this reason and other good reasons be encouraged. With much of the contiguous United States not explored in depth and with some opinion, as in figure 5, that large areas of the country are favorable to the occurrence of oil and gas, the situation would appear to deserve serious consideration, not only to set policy but to design a program to stimulate the discovery of such resources fully adequate to our needs at least until the use of atomic energy is more fully developed.

FIGURE 5

Occurrence of oil and gas in the United States



Source: United States Petroleum Through 1980, U.S. Department of the Interior, 1968.

Regulation

The Water Quality Improvement Act of 1970 (Public Law 91-224) prescribes authority for the Federal Government to regulate control of pollution by oil from vessels and from onshore or offshore drilling facilities. Operators may be liable for cleanup costs up to a ceiling of $14 million in case of an accidental spill. The Government has the authority to immediately conduct cleanup operations and to bill the responsible party later.

With certain aspects of complex Federal-State proprietary and administrative relations not fully resolved, control of environment pollution is still evolving. Efforts to fix oil-spill responsibility and penalties for discharges of oil from ships, tankers and barges as well as from coastal and river terminals is one thing. Truly workable rules under which offshore lease and development of potential oil and gas resources will proceed without serious danger of pollution is quite another matter. Some of the extreme difficulties, present and potential, involved in maintaining an environment of acceptable quality in the case of offshore petroleum development are illustrated by the long continued Santa Barbara Channel problem widely noted in public information sources, and the more recent problem off the Louisiana coast.

A go-slow policy for offshore drilling?

All of this would appear to raise a policy question of withholding or delaying further offshore lease and development until fully adequate technology is more nearly in hand for producing and transporting such petroleum. The very high public and private costs incurred in offshore development in the recent period, the possible irreparable damage done to some resources and the fact that several aspects of technology, legislation and law are yet to be worked out or clarified would seem to suggest a "go slower" policy.

NATURAL GAS

One-sixth of all the natural gas consumed in this country is used for electric power generation. The amount so generated accounts for about one-quarter of all electrical energy generated by steam-electric plants. Natural gas is a desirable fuel for power generation because of its ease of handling, relatively low capital investment in gas-fired plant facilities, minimal waste disposal problems and ability to meet air quality standards in practically all regions of the country.

There is considerable doubt, however, that domestic natural gas supplies will be adequate to meet all foreseeable demands for this commodity in the next two decades, even allowing for success in AEC's Plowshare program. Energy economists believe that in the years ahead synthetic gas from coal and liquified natural gas (LNG) imports will play an increasingly important role in our gas supply picture. The announcement by the El Paso Natural Gas Co. this month of plans to import 1 billion cubic feet of gas per day in liquid form from Algeria, probably marks the beginning of substantial imports of natural gas form foreign sources. El Paso has estimated a price of 50 cents per thousand cubic feet (Mcf) at dockside on the east coast, based on deliveries in 1973. Storage of the LNG and regasification would add approximately another 4 cents per thousand cubic feet (Mcf) to the price. At 54 cents per thousand cubic feet

(Mcf), LNG may be approaching competition with new gas, residual oil, or coal for electric power generation in the high fuel cost Middle Atlantic and New England areas, particularly where stringent air pollution control regulations are in force. Imported LNG for baseload electric powerplant operation, however, does not appear to be competitive with nuclear power at the present time. Synthetic gas of high British thermal unit content (pipeline quality) produced from coal in quantities that would be competitive in price with imported LNG, is at best probably 8 to 10 years away.[1]

Supply and demand for natural gas

Attention has already been called to the fact that the Paley Commission in 1952 greatly underestimated the contribution which gas would make as an energy source in generating electricity in the years ahead. Referring to tables 3 and 4, in 1950 some 777 billions of cubic feet of gas had provided about 13.5 percent of the energy needed in generation; they estimated that in 1975, 1,600 billion cubic feet would be consumed in generating electricity, to produce about 10.7 percent of the total generated. But in 1968 (table 5) about 3,100 billion cubic feet of gas were used in generation, or about 23 percent of the total energy resource required for the purpose. The projection for year 2000 (table 5) would indicate the use of 4,000 billion cubic feet of gas for generation of electricity, but gas would supply only 4.8 percent of the total energy required for generation, as compared with 23 percent in 1968.

It is emphasized in the preceding section on oil that natural gas resources are often intimately associated with petroleum, in exploration, in development and in production—that to a degree they share a common domain and may be referred to as the petroleum group of fossil fuels. Some tables and discussion deal separately with natural gas liquids. For this reason and others, some joint aspects were covered in the petroleum section. It may be noted here that coal, also previously discussed, represents about 73 percent of the total resources of fossil fuel in the United States, whereas natural gas (dry) represents only 4 percent of the total. Nevertheless, the petroleum group of fossil fuels (petroleum, natural gas liquids, and natural gas), which represent only 9 percent of the total fossil fuel supply, are now being used about twice as fast as coal which represents 73 percent of the fuel supply.

As previously noted, the experts present approximately as wide a range of estimates for natural gas as for petroleum, a not unexpected situation in view of the substantial degree of association in nature and exploitation. Even in 1967, about one-fourth of net gas production was from oil wells. It is stated that during the last 20 years, the ratio of natural-gas discoveries in the United States to those of crude oil have averaged about 6,000 ft^3/bbl.[2]

Again, as in the case of petroleum, there is a problem of definition, but in 1967 estimated recoverable proved reserves, including offshore reserves for California, Louisiana, and Texas amounted to nearly 293 trillion cubic feet of gas. Texas, Louisiana, Oklahoma, Kansas, and New Mexico held much of the reserve. The same States in that year provided the great bulk of the marketed production (table 21) which in total amounted to something more than 18 trillion cubic feet, of which about one-sixth was used as fuel for the generation of electricity.

[1] Testimony of Federal Power Commission before the Joint Committee on Atomic Energy, November 1969, cf. "Environmental effects of producing electric power," op. cit., p. 57.
[2] Hubbert, op. cit., p. 187.

TABLE 21.—NATURAL GAS—PRODUCTION, 1940 TO 1967, AND RESERVES, 1955 TO 1967, BY STATES

[In billions of cubic feet]

State	Marketed production [1]						Reserves [2]			
	1940	1950	1955	1960	1965	1967	1955	1960	1965	1967
Total	2,660	6,282	9,405	12,771	16,040	18,171	223,697	263,759	286,469	292,908
Arkansas	14	48	32	55	83	117	1,164	1,460	2,269	2,811
California	352	558	538	518	660	681	8,893	8,844	8,832	7,724
Colorado	3	11	49	107	126	117	2,254	2,043	1,718	1,769
Illinois	8	13	8	12	7	5	234	173	210	259
Kansas	90	364	471	634	793	872	16,293	19,620	16,596	15,284
Kentucky	53	73	73	75	79	89	1,262	1,144	1,092	954
Louisiana	343	832	1,680	2,988	4,467	5,717	42,436	63,386	82,811	86,290
Michigan	13	11	8	21	35	34	326	586	746	761
Mississippi	6	114	163	172	167	139	2,608	2,542	1,973	1,597
Montana	26	39	28	33	28	26	730	626	596	838
Nebraska	(3)	(4)	13	15	11	8	203	118	80	64
New Mexico	64	213	541	799	937	1,068	18,585	15,604	15,375	15,092
North Dakota	(3)	1	5	19	36	40	281	1,151	1,121	882
Ohio	41	43	34	36	36	41	810	766	755	763
Oklahoma	258	482	615	824	1,321	1,413	13,205	17,311	20,357	19,404
Pennsylvania	91	91	99	114	84	90	754	1,192	1,257	1,392
Texas	1,064	3,126	4,731	5,893	6,637	7,189	108,288	119,489	120,617	125,415
Utah	(3)	4	17	51	72	49	421	1,526	1,439	1,227
West Virginia	189	190	212	209	207	211	1,565	1,831	2,494	2,580
Wyoming	27	62	78	182	236	240	3,196	3,935	3,703	3,685
Other States [5]	19	5	9	12	18	25	201	411	2,428	4,117

[1] For 1940, amount used by ultimate consumer only; thereafter, comprises gas sold or consumed by producers, including losses in transmission, amounts added to storage, and increases in gas in pipelines. Beginning 1965, data on pressure base of 14.73 pounds per square inch absolute; prior years, 14.65.

[2] Estimated recoverable proved reserves. Offshore reserves included for California, Louisiana, and Texas. Excludes gas loss due to natural-gas liquids recovery. Source: American Gas Association.

[3] Included with "Other States."

[4] Less than 500,000,000 cubic feet.

[5] Prior to 1960, excludes Alaska.

Source: Statistical Abstract of the United States, 1969, op. cit., p. 672.

If even some lower figure in the range of estimates is accepted as being the more probable, there is still a lot of gas to be found and developed. Cumulative production plus accepted estimates of proven reserves for coterminous United States gives approximately 600 trillion cubic feet. To that, Hubbert, one of the more conservative estimators, would add 222 trillion cubic feet for the fields already discovered, beyond the 286 trillion feet of proved reserves.[1] Then he would add another 218 trillion cubic feet for future discoveries, or a total for the lower estimates of possible gas (Zapp, for example, is much higher) of about 1,044 trillion cubic feet, of which only about one-third has yet been produced.

The possibility of shortage

But there can be little question that the ratio of proved reserves to production did decline in 1968 (table 22) and again in 1969, creating more than a little alarm in some quarters. Others argue that such reserve data as published can be extremely misleading.[2] At the same time it is evident from the exploration statistics found in table 23 that emphasis on new discoveries has for one or several reasons been deemphasized.

[1] Hubbert, op. cit., pp. 187–188.

[2] See for example the discussion by Bruce C. Netschert, in "Natural Gas Supply Study," hearings before the Subcommittee on Minerals Materials and Fuels of the Committee on Interior and Insular Affairs, U.S. Senate, 91st Cong., 1st sess., November 1969, Government Printing Office, Washington, 1970, at pp. 78–95.

TABLE 22.—U.S. NATURAL GAS RESERVE—PRODUCTION HISTORY

	Net production	Percent from oil wells	Gross added to reserve	Proved reserve year end	Ratio: Proved reserve to production	Ratio: Annual reserve added to production
Year:						
1945	4.9	34		146.9	30.0	
1950	6.9	34	12.0	184.6	26.8	1.69
1955	10.1	33	21.9	222.5	22.1	1.95
1956	10.8	33	24.7	236.5	21.8	2.29
1957	11.4	32	20.0	245.2	21.4	1.75
1958	11.4	30	18.9	252.8	22.2	1.66
1959	12.4	29	20.6	261.2	21.1	1.68
1960	13.0	28	13.9	262.3	20.2	1.07
1961	13.4	28	17.2	266.3	19.8	1.28
1962	13.6	27	19.5	272.3	20.0	1.43
1963	14.5	26	18.2	276.2	19.0	1.25
1964	15.3	25	20.3	281.3	18.4	1.33
1965	16.3	25	21.3	286.5	17.6	1.31
1966	17.5	27	20.2	289.3	16.5	1.15
1967	18.4	26	21.8	292.9	15.9	1.18
1968	19.4	24	13.8	[1] 287.4	14.8	.71

[1] 22 percent of reserves at Dec. 31, 1968, were associated dissolved.

Source: AGA Gas Facts, U.S. Bureau of Mines; "Natural Gas Supply Study, op. cit., p. 18.

TABLE 23.—EXPLORATION STATISTICS

	Total well completions: All wells	Total well completions: Gas wells	Exploratory wells: Total	Exploratory wells: Gas wells
Year:				
1945	24,879	(1)	5,613	374
1950	43,279	(1)	10,306	431
1955	56,682	(1)	14,937	269
1956	58,160	4,543	16,173	822
1957	55,024	4,620	14,702	865
1958	50,039	4,803	13,199	822
1959	51,764	5,029	13,191	912
1960	46,751	5,258	11,704	868
1961	46,962	5,664	10,992	813
1962	46,179	5,848	10,797	771
1963	43,653	4,751	10,664	664
1964	45,236	4,855	10,747	587
1965	41,432	4,724	9,466	515
1966	37,881	4,377	10,313	578
1967	33,558	3,619	9,059	556
1968	32,914	3,329	8,879	486

[1] Not available.

Source: American Association of Petroleum Geologists; Natural Gas Supply Study, op. cit., p. 17.

According to the Chairman of the Federal Power Commission, discernible trends of supply and demand indicate a developing natural gas shortage in the United States.[1]

Short-range effects appear to be that some pipeline suppliers in parts of the United States may be unable to meet demands of the gas distribution companies for new service in the winter of 1970–71. Over the longer term, assuming that the present annual growth in demand continues for natural gas and that additions to the supply do not correspondingly increase from new discoveries in the lower 48 States or supplementary sources,[2] it is manifest to the FPC that total gas energy demands will not be met by the natural gas industry. How the utilities would make out in competing for short natural gas supply is not clear.

[1] See also "A Staff Report on National Gas Supply and Demand," Federal Power Commission, Oct. 1, 1969. App. A to this report asserts (at p. 1): "Evidence is mounting that the supply of natural gas is diminishing to critical levels in relation to demand."

[2] I.e., liquified natural gas, gasified coal, increased imports of gas from Canada or delivery of natural gas from the North Slope of Alaska.

The Chairman of the Federal Power Commission cautions that there is no immediate solution to the gas supply problem. No single factor is determinative in assuring new domestic gas supplies to meet growing demands, including those of the electricity industry. The precise dimension or magnitude of this problem cannot be established, in his opinion, until probative evidence relevant to the problem has been presented in rate proceedings before the Commission, or until a reliable gas survey has defined supply in relation to deliverability and demand.[1]

FPC Commissioner John A. Carver takes a stronger stand. Pointing out that one-sixth of all natural gas produced in the United States is used for power generation, he further observes:

> At a time when we are seeking incentives for increased exploration and production, when increased imports from Canada and transport in liquid form are being planned and when research on conversion of coal to gas is being accelerated, it would seem foolhard in the extreme to count it heavily in our inventory of potential electric power sources.[2]

These views raise in the minds of some the question of whether new additional commitments of gas for boiler fuel use should be permitted. With greatly expanding use in homes etc., higher priorities, whether set by administration or by the market may exist.

Environmental effects of producing natural gas

It may be noted that natural gas, in production and in use appears to present fewer environmental pollution problems than coal, or petroleum and probably fewer than nuclear fuel or dams for hydroelectric power.

NUCLEAR FUELS

The fuel for nuclear power to the 1990's will be mainly uranium (some plutonium). Nuclear powerplants to the mid 1980's probably will use only the uranium-235 isotope, which amounts to 0.7 percent of the uranium atoms in uranium ores. Thorium is not yet in use as a nuclear fuel and will have to await perfection of the breeder type reactor. Current reactor technology uses about 0.6 to 1.2 percent of the potential energy in the uranium ores and with improvements might increase to 3 percent.[3] More effective use (other uranium isotopes) will have to wait for the successful demonstration of the breeder reactor. This technique converts non fissionable atoms to fissionable isotopes at the same time that power is produced from the original fuel change. In theory, a combination of breeder and conventional nuclear reactors could permit use of all the atoms of uranium and thorium for fuel.

As a practical matter, breeding initially is likely to make use of somewhat more than half of the available atoms;[4] and later about 70 percent.

At present the manufacturing processes that transform uranium concentrates into fabricated nuclear fuel have few environmental effects. The operations are chemical and metallurgical processes that generate much the same kinds of wastes one would expect from similar operations with nonradioactive materials. Pollution problems are likely to

[1] Statement of Hon. John N. Nassikas to the Senate Commerce Committee, Jan. 30, 1970, p. 94.

[2] Remarks of Commissioner John A. Carver at the Annual Conference of the Atomic Industrial Forum, Inv., Dec. 1, 1969.

[3] Energy R. & D. and national progress, p. 105.

[4] Robert D. Nininger, "Importance of Increased Supplies of Nuclear Fuels To Meet Long-Term World Energy Requirements," in "AEC Authorizing Legislation—Fiscal Year 1970." Hearings before the Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, pt. 3 ,p. 2329.

appear through effects of acids and other chemical wastes, rather than the slight radioactivity of any uranium wastes.

For the future, the manufacture of fuel materials and fabrication of nuclear fuel may become more hazardous as plutonium and uranium-233 come into use. There may then be the possibility of these materials escaping to contaminate the surrounding area, as recently happened at the AEC's weapon's factory at Rocky Flats, Colo. How likely such release may be will depend upon the regulations imposed by the AEC upon the private factories.

The Atomic Energy Commission believes that breeders will extend energy resources indefinitely, but acknowledges that until breeder reactors can be put into general use, the Nation faces an immediate problem of producing enough uranium to fuel present nuclear power reactors to meet short-term electrical energy requirements.[1] One measure of this problem is the controversy over the proposed sale to private interests of the AEC's gaseous diffusion plant at Oak Ridge, Tenn., which manufactures nuclear fuel materials enriched in the U^{235} atoms.

Domestic uranium resources

Table 24 summarizes the AEC's estimate of February 1967 that the uranium resources of the United States are the equivalent of 875,000 tons of (U_3O_8), known as "black oxide," and 1,705,000 tons for the free world outside of the United States. Through 1980, U.S. uranium requirements for civilian nuclear power are estimated at about 170,000 tons, based on nuclear capacity of 95 million kilowatts in 1980.[2]

TABLE 24.—NATURAL URANIUM RESOURCES[1]

[In thousands of tons U_3O_8]

	United States	Free world excluding United States	Total free world
Less than $10/lb. U_3O_8:			
Reasonably assured[2]	200	485	685
Estimated additional[3]	325	355	680
Total	525	840	1,365
Less than $15/lb. U_3O_8:[4]			
Reasonably assured	350	1,050	1,400
Estimated additional	525	655	1,180
Total	875	1,705	2,580

[1] AEC 1960 projections.
[2] Demonstrated reserves.
[3] Based on geologic and exploration data.
[4] Includes less than $10/lb. U_3O_8.

Source: Civilian nuclear power. The 1967 supplement to the 1962 report to the President. February 1967, U.S. Atomic Energy Commission, p. 15.

The AEC's estimate for yearend uranium reserves for December 1968 recoverable at $8 per pound of U_3O_8 or less was 161,000 tons of U_3O_8, representing a net increase of 13,000 tons over the year.[3] Reserves at a price of $10 per pound or less were estimated at 200,000 tons.

[1] Loc. cit.
[2] "Civilian Nuclear Power," the 1967 supplement to the 1962 report to the President, Washington, D.C., U.S. Atomic Energy Commission, February 1967, p. 15.
[3] "AEC Authorizing Legislation, Fiscal Year 1970," hearings before the Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, pt. 3, p. 309.

The economic feasibility of present nuclear power depends upon a price of $10 per pound or less. In addition to these reserves in conventional deposits mined principally for the uranium, AEC estimates there are some 120,000 tons of U_3O_8 that might be recovered through the year 2000 as a byproduct from the processing of phosphate rock and copper mine waste leach solutions. This material is all regarded as available at $10 per pound or less.[1]

In May 1969, the AEC published a revised uranium ore estimate for the Western United States to total 70,300,000 tons of ore. This ore has an average uranium content of 0.23 percent and contains an estimate 161,000 tons of U_3O_8 recoverable at $8 or less per pound. These figures represented an increase in reserves during 1968 of 6 million tons of ore containing an estimated 13,000 tons of U_3O_8 despite the 13,000 tons of U_3O_8 in ores delivered from the uranium mines to the uranium mills.

The breakdown of this latest estimate of ore reserves by States appears in table 25.[2]

TABLE 25.—URANIUM ORE RESERVES

State	Tons of ore	Percent U_3O_8	Tons of U_3O_8
New Mexico			
Wyoming	29,400,000	0.25	72,600
Utah	32,000,000	.20	62,700
Colorado	3,000,000	.32	9,600
Texas	2,800,000	.28	7,700
North and South Dakota	1,300,000	.28	3,700
Others: (Arizona, Alaska, Washington, Nevada, California, Oregon, Montana, and Idaho)	400,000	.30	1,260
	1,400,000	.25	3,440
Total	70,300,000	.23	161,000

Source: AEC press release.

The heat energy potential in the known U.S. uranium reserves is estimated at about 9 quintillion B.t.u.'s if breeder reactors are perfected, but about 1 to 3 percent of that amount with present nuclear power technology. The heat value of the 3,270,000 tons of uranium metal estimated by the Geological Survey for unappraised and undiscovered domestic deposits in the United States and recoverable at $100 per pound of U_3O_8 or less comes to about 784 quintillion B.t.u. These figures may be compared with current annual U.S. consumption of about 0.06 quintillion B.t.u. or known recoverable coal reserves in the U.S. of 4.6 quintillion B.t.u.

As for thorium, since it is not yet a proven source of nuclear energy, prospecting for it has been limited. Known deposits minable at a cost of $5 to $10 per pound of thorium dioxide (ThO_2) total about 108,000 tons. Estimates of unappraised and undiscovered resources by the U.S. Geological Survey in this price range come to 800,000 tons of thorium metal. In the price range of $10 to $30 per pound of ThO_2, the Survey estimates about 100,000 tons in known deposits and 1,700,000 tons in unappraised and undiscovered resources. World resources of

[1] "AEC Authorizing Legislation, Fiscal Year 1970," hearings before the Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, pt. 3, p. 1806.

[2] If the energy from the 3,700 tons of U_3O_8 estimated in the Texas reserves were fully utilized in breeder reactors, it would be the equivalent of 32 billion barrels of oil. For present nuclear technology, it would be equivalent to about 320 million barrels.

thorium in known deposits minable under present economic conditions total about 700,000 tons and undiscovered resources are expected to range from 20 to 200 million tons.[1]

The energy value of known deposits of thorium in the United States is about 12 quintillion B.t.u.'s. The AEC estimates the energy vlaue of unappraised and undiscovered thorium deposits in the United States as 128,500 quintillion B.t.u.'s.

Uranium requirements

In 1967 the AEC estimated uranium requirements for domestic nuclear power at 170,000 tons of U_3O_8 based upon an estimated nuclear powerplant capacity of 95 million kilowatts in 1980.[2]

In April 1969 the estimate given was 237,000 tons of U_3O_8 for the years 1969 through 1980, with an annual requirement of 38,000 tons of U_3O_8 by 1980. Although the estimated requirements through 1980 greatly exceed current reserves at $8, the AEC testified that the exploratory drilling and prospecting efforts and the results being achieved therefrom "* * * provide encouragement that the resources needed will be found."[3]

In addition to the immediate estimated needs through 1980, the AEC has factored in a 8-year reserve as being necessary to provide a minimum production base for uranium mining and processing. Thus for domestic nuclear power through 1980, production plus reserves is estimated at about 600,000 tons of U_3O_8, which will require new discoveries exceeding 440,000 tons. In December 1969, presently known reserves were stated at 160,000 tons for $8 per pound U_3O_8.[4]

AEC notes the discrepancy between the known reserves in 1969 and the projected requirements through the year 2000. Even assuming that fast breeder reactors are introduced in the late 1980's, the cumulative requirement through the year 2000 is for 1 million tons of U_3O_8. Reserves at $10 per pound or less were estimated in 1969 at 320,000 tons of U_3O_8, including the 120,000 tons of byproduct material mentioned above. AEC estimates that current additional undiscovered resources in the $10 per pound price could add another 350,000 tons of U_3O_8 and that resources of materials in the $10 to $15 per pound category are estimated at 350,000 tons.[5]

Uranium mining

Uranium is mined mainly in 10 Western States, five of which produce over 90 percent of the total domestic uranium ore (JCAE–W. Miners 1967 P102).

Three types of uranium deposits are worked:

(1) Extensive deep deposits as in the lower Chinle formation of the Big Indian Wash district of Utah, and in the sandstones of the Grants-Ambrosia Lake districts of New Mexico. Here the ore bodies are large and highly mechanized handling and hauling equipment can be used.

(2) Extensive shallow deposits, as in the Gas Hills district of Wyoming. Here open pit methods are used.

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[1] "Energy R. & D. and National Progress," op. cit., pp. 110-112.
[2] "Civilian Nuclear Power," the 1967 supplement to the 1962 report to the President, op. cit., p. 15.
[3] "AEC Authorizing Legislation, fiscal year 1970," op. cit., p. 1807.
[4] "The Nuclear Industry, 1969," U.S. Atomic Energy Commission, 1969, p. 35.
[5] "AEC Authorizing Legislation, Fiscal Year 1970," op. cit., p. 1807.

(3) Irregular shallow deposits, such as the carnotite occurrences in the Salt Wash Formation of the Uravan Mineral Belt of Colorado and the copper-uranium ores in the White Canyon district of Utah. Here various techniques are used.

The largest ore bodies mined by underground methods measure as much as half a mile in length, several hundred feet in width, and from 5 to 100 feet in thickness, and are located several hundred feet or more below ground. In most cases the ore is worked from vertical or inclined shafts. Open pit mining permits more complete ore recovery than underground mining and allows the grade of ore to be readily controlled by selective mining and blending.

In 1968, according to latest figures of the Bureau of Mines, approximately 320 mining operations in eight States produced almost 6.5 million tons of uranium ore, 22 percent more than was produced by some 500 operations in 1967. New Mexico lead in production and accounted for 51 percent of the total recoverable uranium, followed by Wyoming with 25 percent, Colorado with 11 percent, and Utah with 7 percent. Following were Texas, Arizona, South Dakota, and North Dakota.[1]

Uranium processing

Uranium ores were processed at 16 mills during 1968 and ore concentrates containing 7,338 tons of U_3O_8 were shipped to the AEC from 13 of these mills. This compared with 8,425 tons shipped from 16 mills in 1967.

Substantial quantities of uranium were processed for private industry also during 1968 with slightly more than 5,000 tons of U_3O_8 sold compared with an estimated 700 tons in 1967. Sales to private industry, which represented about 40 percent of mill production in 1968, are expected by the Bureau of Mines to increase both in volume and relative percentage as uranium is required to fuel nuclear power plants and as the AEC ends its own uranium buying.[2]

The AEC expects that an additional 8,000 to 9,000 tons could be added by the mid-1970's. Fourteen uranium ore processing mills are currently in operation, with 90 percent of their production from uranium mines that they own or control.[3]

Environmental effects of uranium mining

The environmental effects of uranium mines are similar to those of other mining operations using pit and open mining techniques.

Hazards of uranium mining.—Uranium miners are exposed to the usual mining hazards such as accidents, and exposure to silica dust, diesel and explosive fumes, and intense noise. In addition, they also may be chronically exposed to dangerous concentrations of radioactive gas.

Uranium in nature is slightly radioactive. It gives off a radioactive gas, radon, which escapes into the air from exposed rock surfaces within a mine. Radon, being much heavier than air, collects in the mines. The radon subsequently changes into solid radioactive particles

[1] U.S. Department of the Interior, Minerals Yearbook, vol. I-II, "Metals, minerals, and fuels." Washington, D.C., U.S. Government Printing Office, 1969, p. 1118.

[2] Ibid., p. 1118.

[3] "The Nuclear Industry 1969," op. cit., p. 37.

which are deposited and retained in the lungs of miners. The radon in the air breathed and the radioactive daughter products of the radon expose the lungs of miners to radiation.

Studies by the U.S. Public Health Service in cooperation with the Atomic Energy Commission and State agencies disclose that underground uranium miners are subject to lung cancer to a degree substantially greater than the general population, or that of miners in other kinds of underground mines. This excess incidence of lung cancer in uranium miners is believed to be induced by their exposure to radiation from the radioactive decay of the radon daughters in their lungs.[1]

At present there is some disagreement whether it is possible or economically feasible to reduce radon exposure to the levels set by the Department of Labor.

Wastes from uranium milling.—Uranium mills can be a source of environmental contamination because the process wastes contain radioactive materials, mainly radium, and toxic chemicals which may be released to the environment. For example, about 865 gallons of waste liquids are produced per ton of ore treated. Initially, wastes were allowed to flow or seep into the ground, where they might enter the water table. Typically, a uranium mill must dispose of approximately 10 curies of radium per day in one way or another.[2] This is considered to be a large amount of radioactive material.

Of 26 mills in operation in 1963, 10 discharged the liquid effluent from their tailings to streams. For example, in 1958 and 1959 it was found that consumers of untreated water along the Animas River in southwestern Colorado below mills in Durango were receiving almost 300 percent of the maximum permissible daily intake for radium recommended by the International Committee on Radiation Protection, while the cities of Aztec and Farmington received 170 and 140 percent of the daily permissible intake respective. Of the given total daily intakes, from food as well as water, about 61 percent of the radium came from plants which had taken up the radium from contaminated irrigation water.[3] Since then corrective measures have reduced the exposures to one-third of levels recommended by the U.S. Public Health Service.

Chemical wastes from mills also can have environmental effects. For example, organic raffinate, a waste from the ore extraction, was originally discharged directly into the Animas River even though very lethal to fish. Until this discharge was stopped, some 50 miles of the river below the mill was devoid of fish and the food that fish live on.[4]

Production of uranium concentrates has resulted in the accumulation of uranium mill tailings piles in sizes ranging from several thousand to several million tons in the basin of the Colorado River. In all but one case, there were in 1966 no measures to contain the tailings and the piles were left exposed to erosion by wind and rain. The fines in the

[1] "Radiation Exposures of Uranium Miners," hearings before the Joint Committee on Atomic Energy, 90th Cong., 1st sess., 1967, pt. 2, p. 1021.
[2] M. Eisenbud. "Environmental Radioactivity," New York, McGraw-Hill Book Co., 1963, p. 174.
[3] Eisenbud, op. cit., p. 176.
[4] "Radioactive Water Pollution in the Colorado River Basin," hearing before the Subcommittee on Air and Water Pollution, Senate Committee on Public Works, 89th Cong., 2d sess., 1966, p. 3.

tailing were easily carried away by wind and rain. They also contained the most radium per unit weight of waste. Some of the tailings piles were immediately adjacent to population centers. Many of the piles were at closed down and abandoned mills, with no one responsible for possible preventive measures.

The problem of radioactive water pollution in the Colorado River Basin from uranium mills was the subject of hearings held by Senator Muskie and the Senate Subcommittee on Air and Water Pollution in 1966.[1]

Regulation of uranium production

Responsibility for regulating various steps in the mining, refining, processing and fabrication of uranium into nuclear fuel is divided between the States and the Atomic Energy Commission. Briefly, regulation of mining, milling of uranium ores, extraction of the uranium and subsequent chemical processing of it would be the responsibility of the States. At present only the AEC performs the enriching of uranium fuel materials in the U^{235} isotope, so control of any environmental effects of this operation is directly an AEC operational matter. Subsequent fabrication of enriched fuel materials into fuel is done under AEC licenses to possess this material, so that control of the U^{235} for reasons of security and environmental protection is with the AEC.

HYDROPOWER

Generation of electricity by hydropower has declined in terms of the total to less than 17 percent in 1968; some estimates reduce it to only 7 percent of the larger total in year 2000.

Information in table 26 indicates that substantial development of water power resources has taken place since World War II, with installed capacity somewhat more than doubled. Even so, about two-thirds of the estimated ultimate potential remains for possible development. Significantly, about three-fourths of the estimated undeveloped potential is in the Pacific border States, especially Alaska, and in the Mountain States, some of which have very substantial resources of coal and petroleum.

Environmental effects

The building of dams to develop hydropower presents at least one major environmental problem in as much as flooding of important valley land removes it permanently from major food production. In some areas population centers, generally smaller ones, are also flooded and the local economy disorganized. In areas of considerable soil erosion, siltation of the lake created behind the dam must be anticipated. An offsetting feature is the increased recreational resources and reserve water supplies which are created.

[1] "Radioactive Water Pollution in the Colorado River Basin," hearing before the Subcommittee on Air and Water Pollution, Senate Committee on Public Works, 89th Cong., 2d sess., 1966.

TABLE 26.—WATER POWER—DEVELOPED, 1950, 1960, AND 1967, AND ESTIMATED UNDEVELOPED, 1967. STATES

[In thousands of kilowatts, as of December 31]

State	Developed water power [1] (capacity of actual installations only)			Estimated undeveloped water power, 1967
	1950	1960	1967	
United States	[2] 18,675	33,180	45,826	130,444
N.E.	1,239	1,520	1,491	3,304
Maine	391	495	510	1,714
N.H	312	445	429	802
Vt	192	199	200	338
Mass	223	227	219	267
R.I	11	3	3	0
Conn	107	151	131	183
M.A	1,678	2,472	4,247	4,514
N.Y	1,225	2,028	3,809	1,292
N.J	9	8	8	241
Pa	444	436	430	2,981
E.N.C	901	929	969	1,256
Ohio	16	9	2	249
Ind	37	31	110	315
Ill	54	42	43	206
Mich	399	419	395	272
Wis	396	427	419	213
W.N.C	629	1,594	2,734	4,363
Minn	181	186	170	157
Iowa	137	136	136	345
Mo	151	293	393	2,025
N. Dak	0	400	400	195
S. Dak	11	333	1,392	303
Nebr	142	240	238	1,036
Kans	6	6	5	303
S.A	2,767	3,773	5,349	9,468
Del	1	1	0	0
Md	272	272	494	160
D.C	3	3	3	3
S.A.—Continued				
Va	207	416	726	1,276
W. Va	208	208	208	1,994
N.C	962	1,220	1,766	919
S.C	679	958	1,034	1,315
Ga	425	653	1,069	3,197
Fla	13	42	39	84
E.S.C	2,729	3,750	4,832	3,943
Ky	271	541	671	1,485
Tenn	1,238	1,910	1,894	688
Ala	1,220	1,299	2,267	1,630
Miss	0	0	0	140
W.S.C	466	944	1,698	3,065
Ark	148	388	900	915
La	0	0	0	76
Okla	74	165	363	914
Tex	245	391	434	1,160
Mt	2,286	4,621	6,083	26,891
Mont	427	1,235	1,512	6,269
Idaho	441	1,251	1,251	12,392
Wyo	79	189	212	1,286
Colo	92	253	314	1,875
N. Mex	25	25	24	154
Ariz	541	980	1,879	3,676
Utah	94	100	208	1,320
Nev	587	587	682	9
Pac	[2] 5,979	13,578	18,425	73,640
Wash	2,591	7,002	9,549	23,499
Oreg	783	2,434	3,449	5,656
Calif	2,606	4,054	5,324	11,909
Alaska	(3)	67	84	32,511
Hawaii	(3)	21	19	35

[1] Electric utilities and industrial plants, excluding pumped storage capacity.
[2] Excludes Alaska and Hawaii.
[3] Not available.

Source: Federal Power Commission; annual summaries and related monthly reports; Statistical Abstract of the United States 1969, op. cit., p. 518.

IMPORTED ELECTRICITY

Another alternative is to import electricity. Canada has large, undeveloped resources for hydropower. From time to time there have been proposals to import a large block of electricity into the northeastern part of the United States.

Recently there was talk again of such arrangements. At one time Consolidated Edison of New York was reported to be negotiating to purchase 5,225 megawatts from a hydroelectric station at Churchill Falls in Labrador. Subsequently Quebec Hydro contracted for all available power from this project. Recently, however, work has begun on a 2,200-megawatt project downstream from Churchill Falls, and this project is expected to provide extremely attractive electricity to utilities in New England.

The Electricity Industry

The most recent major analysis of the industry appeared in the national power survey of the Federal Power Commission, published in 1964. That survey is now being updated and a revised version is expected in the summer of 1970. Meanwhile the Federal Power Commission has been drawing upon the revised estimates for statements before committees of Congress.

THE ELECTRICITY INDUSTRY IN 1964

In terms of capital investment and assets, the U.S. electric power industry has grown from its conception in the 1880's to a giant ranked the largest in the Nation. It has expanded at a pace nearly twice that of the overall economy, doubling its output every 10 years and increasing at an annual compound rate of almost 7 percent. Electricity supplied 20 percent of the energy used in the United States in 1964 and is expected to supply 30 percent by 1980. The industry's annual rate of productivity improvement has averaged about 5.5 percent since 1900. From the early 1900's through 1940 the price for residential electricity dropped steadily, and has held almost steady until recently when the number of requests to raise rates increased.

Electric power ranks among the largest industries in the economy. Requiring heavy use of capital, its annual capital outlays in 1964 represented over 10 percent of the total of such spending by all American industries. Its spending on plant and equipment in 1962 alone amounted to $4.3 billion. Its capital assets of $69 billion in 1962 were more than 60 percent greater than its nearest rival, petroleum refining with $40.6 billion.

ORGANIZATION OF THE ELECTRICITY INDUSTRY

The electric power industry in 1962 consisted of 3,600 systems which varied greatly in size, type of ownership and power supply functions performed. The pluralistic U.S. electric power industry consists of four distinct ownership segments, those owned by investors, State and local public agencies, cooperatives, and Federal agencies. Details of the size and composition of each segment appears in tables 27 and 28.

The largest segment consisted of 480 private or investor-owned systems which owned 76 percent of the generating capacity and served 79 percent of the retail customers.

TABLE 27.—NUMBER OF SYSTEMS, GENERATING CAPACITY, AND CUSTOMERS SERVED BY U.S. ELECTRIC POWER INDUSTRY,[1] BY OWNERSHIP SEGMENT, 1962

Ownership	Number of systems			Generating capacity, percent of total	Retail customers served	
	Total	Engaged in generating and transmission	Engaged in distribution only		Number	Percent
Investor-owned[2]	480	318	162	76	47,500,000	79.5
Public (non-Federal)	2,124	864	1,260	10	8,118,000	13.5
Cooperatives	969	76	[3] 893	1	5,095,000	7.5
Federal	44	42	2	13		
Total	3,617	1,300	2,317	100	60,713,000	100.0

[1] Excludes Alaska and Hawaii.
[2] Includes 34 industrial concerns that supply energy to other customers.
[3] Many of the distribution cooperatives are also members of generating and transmission cooperatives (the so-called G. & T.'s) and hence participate indirectly in the generation and transmission function.

TABLE 28.—COMPOSITION OF THE U.S. POWER INDUSTRY[1] BY SIZE AND OWNERSHIP, 1962

[Number of systems under separate management or control]

Ownership	Annual energy requirements, billions of kilowatt-hours				
	Over 10	1 to 10	0.1 to 1	Under 0.1	Total
Investor-owned	18	88	85	289	480
Public (non-Federal)	0	20	136	1,968	2,124
Cooperatives	0	1	64	904	969
Federal Government	2	7	6	29	44
Total number of systems	20	116	291	3,190	3,617

[1] Excludes Alaska and Hawaii.

Source: National Power Survey, pt. 1, p. 17.

Second in number of retail customers was the publicly owned segment—including municipalities, public utility districts, and State and county entities. They accounted for 10 percent of the generating capacity and 13.5 percent of the retail customers.

Cooperatives, the next largest segment, were a major factor in rural areas. Largely engaged in distribution, they owned less than 1 percent of the generating capacity but brought electricity to 7.5 percent of the retail customers.

The Federal segment in 1962 had 13 percent of the generating capacity. It does not sell to retail customers. Federal electricity goes to publicly owned systems and cooperatives as preference customers. It also is sold to investor-owned utilities and to industries, such as aluminum producers, which are large power users.

The 100 largest systems in 1962 accounted for about 89 percent of the total electric utility generation.

COMPONENTS OF ELECTRIC POWER SUPPLY

The interdependent parts of a power supply system can be divided into the three functions of generation, transmission, and distribution. The relative cost of each function, based on a composite national average in 1962, is shown in table 29. As with any average, there may be substantial deviations for individual systems. Thus, transmission costs in New York City were less than 4 percent, but almost 20 percent in low population areas of northern Minnesota.

TABLE 29.—TOTAL DELIVERED COST OF POWER—1962

[Composition in percent]

	Fixed charges	Operating expenses	Total cost
Generation	28.2	22.8	51.0
Transmission	7.9	2.0	9.9
Distribution	22.8	16.3	39.1
Total	58.9	41.1	100.0

Source: National Power Survey, pt. 1, p. 26

THE ELECTRICITY INDUSTRY TODAY

Chairman Nassikas of the FPC has recently used the indicators shown in table 30 to describe the present electricity industry in the United States. While some of his data do not precisely coincide in time, they are probably the best figures available until the revised power survey is completed. He shows 3,550 systems with a gross plant investment of $102 billion, a generating capacity of 293 thousand megawatts, and an output of 1.3 trillion kilowatt hours. Among these systems, investor-owned companies were 13 percent of the number and accounted for approximately three-fourths of the plant investment, installed capacity, electricity generated, and sales to ultimate customers.

TABLE 30.—SELECTED INDICATORS FOR THE PLURALISTIC ELECTRIC UTILITY INDUSTRY

	Investor owned	Cooperatively owned	Publicly owned	Totals
Number of systems	437.0	971.0	2,142.0	3,550.0
Percent of total	12.3	27.4	60.3	100
Gross plant investment (millions)	$76,025.0	$6,167.0	$20,200.0	$102,392.0
Percent of total	74.3	6.0	19.7	100
Kilowatt-hours generated (billions)	1,021.8	14.5	296.0	1,332.3
Percent of total	76.7	1.1	22.2	100
Kilowatt-hours sales to ultimate customers	931.6	54.5	223.0	1,209.1
Percent of total	77.1	4.5	18.4	100
Installed capacity (megawatts)	223,220.0	3,396.0	66,858.0	293,474.0
Percent of total	76.1	1.1	22.8	100

Note: Data on number of systems is for the year 1965. Gross plant investment and installed capacity are as of Dec. 31, 1968. Kilowatt-hours generated and kilowatt-hours sales to ultimate customers and for the calendar year 1968.

Source: Remarks by Chairman John N. Nassikas of the Federal Power Commission before the 28th annual meeting of the National Rural Electric Cooperative Association, Feb. 11, 1970.

Users of electricity

The 1.3 trillion kilowatt-hours of electricity generated by the electricity industry in 1968 brought an income of $18.5 billion from the ratepayers. Sales to ultimate customers of 1,202 billion kwh divided as follows:

	Billion kilowatt-hours	Percent
Residential or domestic	368	31
Commercial and industrial	784	65
All other	50	4
Total	1,202	100

Source: Statistical Abstract of the United States, 1969, p. 516.

The number of customers totaled 68.7 million, of which 61.4 million were residential or domestic and 8 million were commercial or industrial.

Electric utility sales

An insight into the industry's expectations for future sales may be had from the 20th annual electricity industry forecast by the trade journal Electrical World, published in its issue of September 15, 1969.[1]

It shows a doubling of sales from 681 billion kilowatt hours in 1960 to 1,395 billion for 1970, and projections of 2,012 billion for 1975 and 4,030 for 1980. Of the four categories of users—residential, commercial, industrial, and other—residential uses are increasing the most rapidly. Table 31 summarizes the uses for 1960 to 1985.

TABLE 31.—ELECTRIC UTILITY SALES

[Billion kilowatt-hours]

	Residential	Industrial	Commercial	Other	Total
1960	195.6	344.1	114.4	27.1	681.2
1961	208.2	346.6	134.4	29.4	718.6
1962	225.5	373.0	143.6	31.6	773.7
1963	240.7	387.4	165.9	34.1	828.2
1964	261.0	408.3	182.9	35.4	887.5
1965	279.8	432.2	201.4	36.8	950.4
1966	305.4	463.8	225.1	41.4	1,035.6
1967	330.2	484.7	241.7	46.9	1,103.5
1968	366.2	517.3	264.2	50.6	1,198.4
1969	402.0	557.3	290.0	54.5	1,303.8
1970	440.0	585.2	311.0	58.8	1,395.0
1971	481.0	621.0	337.0	67.7	1,506.7
1972	524.0	662.0	363.0	70.7	1,619.7
1973	569.0	705.0	390.0	77.2	1,741.2
1974	615.0	750.0	420.0	86.8	1,871.8
1975	660.0	800.0	450.0	102.2	2,012.2
1980	970.0	1,160.0	620.0	130.0	2,880.0
1985	1,400.0	1,580.0	860.0	190.0	4,030.0

Source: Electrical World, Sept. 15, 1969.

These forecasts do not attempt to anticipate effects of new demands for electric vehicles, automation, and further mechanization of manufactures and electrification of major trunklines and commuter lines of railroads.

Residential sales

Because residential sales of electricity are increasing so rapidly and so immediately, and directly affect the standard of living, they warrant special attention.

Residential sales of electricity by the utilities continue to be the fastest growing market. Sales for heating and air conditioning are increasing rapidly. At the end of 1968 there were 3.4 million electrically heated homes in the United States. By 1990, the Federal Power Commission expects this number to be 25 million. Some utilities found during the summer of 1969 that as much as 25 to 35 percent of their peak loads were attributable to air conditioning or other weather related needs.

[1] Walter D. Brown, "20th Annual Electrical Industry Forecast," Electrical World, vol. 172, Sept. 15, 1969, pp. 85–98.

The "Electrical World" forecast shows residential sales to have been about 30 percent of total electricity sales during the 1960's. "Electrical World" expects them to increase to one-third of the total by 1975. Electrical heating is the fastest growing component of residential sales. The industry goal for 3.6 million all-electric homes is expected to double to 7.2 million by 1975 and to double again to 14.4 million in the following 5 years. If these goals are attained, electric heating would increase from 22 percent of residential sales in 1969 to 27 percent in 1975 and to 40 percent by 1980.[1]

In 1969 the utilities expected to have 61.6 million residential customers, an increase of 20 percent in 9 years. New customers in the 1970's are expected to bring the total to 68.4 million by 1975 and to 75 million by 1980.

From 1960 to 1969 average annual use by residential customers increased from 3,851 to 6,550 kilowatt-hours, up 70 percent. This combination of higher usage and new customers more than doubled residential sales in the 1960's. By 1975 the average residential usage is expected to reach 10,000 kilowatt-hours.

The average annual residential bill in 1969 was $137. It is expected to approach $200 by 1975. The residential market should produce revenues of more than $8 billion for 1969 and over $13 billion for 1975 as residential sales approach a forecast 660 billion kilowatt-hours in that year.

Table 32 gives historical and projected figures on residential use for the years 1960 to 1985.

TABLE 32.—AVERAGE RESIDENTIAL USE AND RESIDENTIAL SALES

Year	Year-end customers (millions)	Use per customer (kilowatt-hours)	Average annual bill	Residential sales (billion kilowatt-hours)	Residential revenue (millions)
1960	51.3	3,851	$95.12	195.6	$4,831
1961	52.4	4,016	98.39	208.2	5,090
1962	53.5	4,257	102.59	225.5	5,429
1963	54.9	4,440	105.23	240.7	5,693
1964	56.1	4,703	108.12	261.0	6,010
1965	57.4	4,933	110.93	279.8	6,295
1966	58.6	5,263	115.26	305.4	6,698
1967	59.8	5,575	120.42	330.2	7,145
1968	61.2	6,056	128.39	366.2	7,697
1969	61.6	6,550	137.55	402.0	8,442
1970	63.0	7,060	148.26	440.0	9,240
1971	64.0	7,580	158.42	481.0	10,052
1972	65.2	8,110	168.69	524.0	10,899
1973	66.4	8,640	178.85	569.0	11,778
1974	67.6	9,180	188.20	615.0	12,607
1975	68.4	9,730	197.52	660.0	13,398
1980	75.2	12,990	250.70	970.0	18,721
1985	81.8	17,240	315.50	1,400.0	25,620

Source: Electrical World, Sept. 15, 1969, p. 90.

PATTERNS FOR 1980—THE FPC FORECAST OF 1964

In its 1964 survey, the FPC described what it thought the pattern for generation and transmission of electricity would be by the year 1980. What follows is summary of the FPC's expectations.[2]

[1] Walter D. Brown, op. cit., p. 89.
[2] Cf. "National Power Survey," pt. 1, pp. 214-265.

Projected capacity

Table 33 shows the projected makeup of the generating capacity required in 1980 by sectors and in summary for the U.S. fossil-fueled, steam-electric plants that then are expected to provide about 67 percent of the needed capacity, of which about 17 percent is shown to be at mine-mouth. Nuclear power was estimated to form about 13 percent of total capacity with the larger amounts in the Northeast and West sectors. Conventional hydro would contribute nearly 15 percent of the 1980 requirements and pumped storage hydro and other peaking sources would provide the remainder. Regionally, the Northeast and the South sectors accounted for about 35 and 32 percent of the U.S. total, the North Central sector 15 percent, the West sector 18 percent.

TABLE 33.—ESTIMATED U.S.[1] GENERATING CAPACITY, 1980

[In gigawatts [3]]

Generating capacity	Northeast sector	South sector	North-central sector	West sector	Total	Percent
Hydroelectric:						
In 1966	6.7	10.2	3.9	21.8	42.6	8.2
Added 1967–80 [2]	3.5	6.8	.2	22.7	33.2	6.3
Total	10.2	17.0	4.1	44.5	75.8	14.5
Fossil fueled steam:						
At load center:						
In 1966	53.0	57.4	21.9	18.9	151.2	28.9
Added 1967–80 [2]	40.8	51.2	14.8	7.0	113.8	21.8
Total	93.8	108.6	36.7	25.9	265.0	50.7
At mine mouth:						
In 1966	13.9	4.5	2.0	.5	20.9	4.0
Added 1967–80 [2]	22.8	18.9	19.0	5.0	65.7	12.6
Total	36.7	23.4	21.0	5.5	86.6	16.6
Nuclear fueled steam:						
In 1966	.8	.0	.3	1.5	2.6	0.5
Added 1967–80 [2]	25.3	13.4	10.0	18.4	67.1	12.8
Total	26.1	13.4	10.3	19.9	69.7	13.3
Pumped storage:						
In 1966	.6	.1	.4	0	1.1	.2
Added 1967–80 [2]	10.9	4.0	2.0	1.0	17.9	3.4
Total	11.5	4.1	2.4	1.0	19.0	3.6
Other peaking:						
In 1966	1.2	1.5	1.4	.2	4.3	.8
Added 1967–80 [2]	1.4	.7	.5	0	2.6	.5
Total	2.6	2.2	1.9	.2	6.9	1.3
In 1966	76.2	73.7	29.9	42.9	222.7	42.6
Added 1967–80 [2]	104.7	95.0	46.5	54.1	300.3	57.4
Total	[4] 180.9	[4] 168.7	[4] 76.4	[4] 97.0	[4] 523.0	100.0

[1] Excludes Alaska and Hawaii; also excludes imports from Canada.
[2] Additions less retirements.
[3] Millions of kilowatts.
[4] The capacity provided for each sector takes into account diversity savings, potential imports from Canada, and the relative difference in reserve requirements for hydroelectric and thermal capacity.

Source: National Power Survey, pt. 1, p. 215.

The FPC studies revealed several trends for 1980, the concentration of hydroelectric resources in the western and southern sectors, the concentration of added nuclear projects in the coastal areas, the continued major dependence on fossil fuel steam-electric generation in the central areas of the Nation, and the moderate demands for peaking resources in the form of pumped storage and other special peaking facilities. In terms of generating capacity to be added from 1967 to 1980, hydroelectric plants were expected by the survey to provide 11 percent of the total, fossil-fuel plants 60 percent, and nuclear plants 22 percent.

From the data presented in table 33, FPC concluded that nearly 50 percent of the total capacity installed in 1980 would be in thermal plants to be placed in service after 1966. Most of this capacity was judged to be supplied from units of 800 megawatts and larger. The projection includes some 135 units of 1,000 megawatts and larger (up to 1,500 mw.) with a total capacity for the Nation of 154,000 megawatts. About 40 of these are nuclear-power units. Most of the smaller units ranged below 400 megawatts and were accounted for by existing units which will remain in service through 1980 and by some units in the smaller sizes currently on order.

The selection of this high proportion of very large units is consistent, FPC believed, with the goal of the lowest possible cost of power. A key element in accommodating these large units in the Nation's medium-and small-size systems will be the existence of strong interconnections that were expected to be achieved by 1980.

For new generating capacity utilizing fossil fuels, it was expected that coal, oil, and natural gas would share in the supply approximately in the proportion of 75 percent, 5 percent, and 20 percent, respectively. The geographic distribution would be much the same as in 1964, with oil generally limited to the coastal areas where other fuel costs are higher, with coal predominating in the heavy-load areas surrounding the extensive coal fields in a broad east-to-west belt from Pennsylvania to Arkansas and in certain areas in the West, and with natural gas as the leading fuel in the load areas bordering the large gas fields in the Southwest.

Cost of generating electricity

The anticipated cost of generating and transmitting bulk baseload power to load centers using the facilities expected to be available between 1975 and 1980 is summarized in table 34. The costs for three alternative power sources as estimated by the FPC survey are indicated where appropriate; namely, power from fossil fuel and nuclear plants near the load centers and power transmitted to load centers from mine-mouth plants.

A significant factor is that bulk power was expected to be available at load centers throughout the country at a maximum of 5 mills per kilowatt-hour with private financing.

Mine-mouth generation

The general locations of new mine-mouth plants which may become a part of the power generation program by 1980 is suggested in table 33. As observed in table 34, the cost of mine-mouth generation plus transmission is in many instances closely competitive with generation at load centers. Hence the amount of mine-mouth capacity

projected by 1980 was regarded only as illustrative, reflecting then current FPC judgment as to the future status of a competitive situation in which the balance is constantly subject to change. The survey projected that about 25 percent of new generating capacity needed by 1980 would be mine-mouth plants. The influence of mine-mouth generation on the economy of future power programs extends beyond its contribution as a generation source per se. Its competitive influence will be a factor in almost all decisions on new capacity and has done much to advance the development of EHV transmission technology and competing forms of energy transport such as the unit train movements of coal and the coal slurry pipeline.

TABLE 34.—ESTIMATED 1975–80 COST OF BULK POWER GENERATED AT LARGE BASELOAD THERMAL STATIONS DELIVERED TO LOAD CENTERS[1]

	Conventional steam plant				Nuclear plant	
	Mine mouth		Load center		Load center	
Load center—No. and Name	Unit size mw	Energy mills/kwh	Unit size mw	Energy mills/kwh	Unit size mw	Energy mills/kwh
1. Boston	1,500	5.7	1,500	5.3	1,000	4.6
2. New York	1,500	4.9	1,500	4.9	1,000	4.6
3. Buffalo	1,500	4.7	1,000	4.0	1,000	4.5
4. Philadelphia	1,500	4.7	1,600	4.5	1,000	4.5
5. Washington-Baltimore	1,500	4.5	1,500	4.5	1,000	4.5
6. Cleveland	1,500	4.9	1,000	4.5	1,000	3.8
7. Detroit	1,500	4.9	1,500	4.5	1,000	3.8
8. Saginaw-Bay City			1,500	4.5	1,000	3.8
9. Ohio River	1,500	3.8	1,500	3.8	1,000	3.8
10. Winston-Salem			[2] 1,200	5.0	1,000	4.1
11. Memphis	1,500	3.0	1,000	3.4	1,000	3.2
12. Knoxville	1,500	2.8	1,000	3.0	1,000	3.2
13. Atlanta	1,000	4.7	1,000	4.6	1,000	4.1
14. Miami	1,000		1,500	4.8	1,000	3.9
15. Pensacola-Mobile	1,000	5.1	[2] 1,000	4.8	1,000	3.9
16. Chicago	1,500	4.4	1,500	4.2	1,000	4.3
17. Minneapolis			[2] 1,000	4.4	1,000	4.3
18. St. Louis	1,500	3.6	1,500	3.6	1,000	4.3
19. Fort Worth-Dallas	1,000	4.4	[2] 1,200	3.7	600	5.0
20. Houston-Galveston			1,500	3.5	600	4.7
21. Tulsa	1,000	4.4	1,000	3.8	600	5.0
22. New Orleans			1,000	3.7	600	4.7
23. Denver	[2] 1,000	4.1	[2] 1,000	4.1	600	4.9
24. Albuquerque	1,000	4.3	[2] 600	4.4	600	4.9
25. Seattle-Tacoma	800	5.0	1,000	5.3	800	4.7
26. San Francisco	1,500	6.2	1,500	4.9	1,000	4.4
27. Los Angeles	1,000	5.5	1,500	5.0	1,000	4.4
28. Phoenix	1,000	4.9	[2] 1,200	4.6	600	5.0

[1] Includes production expenses, fuel, transmission expenses and the fixed charges generally applicable to the region in which the particular plant is located, on production and transmission facilities. Estimates based on large-unit, seasoned plants of 1 to 4 units. Estimates assume no price escalation. Assumed plant factors are 70 percent for conventional steam plants and 80 percent for nuclear plants.

[2] Single unit plant.

Source: National Power Survey, pt 1, p. 219.

Size of generating units

For purposes of the survey, the additional generating units estimated to be required for 1980 were selected from among the larger and more efficient sizes expected to be availble.

FINANCING GROWTH OF THE ELECTRIC INDUSTRY

Presently the electric industry is the Nation's largest single domestic industry in terms of captial investment which now exceeds $100 billion.

To meet projected growth, the electric utilities—investor, publicly and cooperatively owned—must raise $350 billion in new capital by 1990. By contrast, since 1882 the total industry investment has been just over $100 billion.

For 1969 utility captial expenditures for generation, transmission, and distribution were $10.6 billion and are expected to reach $12.6 billion for 1970, an increase of 19 percent. This is double the $6.3 billion outlay by the industry in 1966.

The investor-owned segment is expected to spend almost $10 billion, or 79 percent of the total.[1]

For 1970, generation facilities represent 53 percent of the anticipated total captial outlays and amount to $6.6 billion. Of this, fossil-fueled plants are expected to require $3 billion, up 11 percent from 1969; nuclear plants $2.3 billion, up 57 percent over 1969; and for waterpower, $905 million is forecast, with $196 million of this for pumped-storage installations. Table 35 gives total electric power system capital expenditures as compiled by Electrical World for the years 1959 to 1970.

TABLE 35.—TOTAL ELECTRIC POWER SYSTEM[1] CAPITAL EXPENDITURES

[In millions of dollars]

	Generation		Transmission		Distribution		Miscellaneous		Total	
	Total industry	Investor owned	Total industry	Investor owned	Total industry	Investor owned	Total industry	Investor owned	Total industry	Investor owned
1959	2,369	1,519	708	554	1,413	1,163	180	146	4,669	3,383
1960	2,226	1,342	715	537	1,565	1,300	183	152	4,690	3,331
1961	2,114	1,267	764	579	1,550	1,265	180	145	4,608	3,256
1962	1,693	1,078	792	609	1,593	1,306	193	162	4,271	3,154
1963	1,721	1,165	837	644	1,568	1,323	230	187	4,357	3,319
1964	1,814	1,113	1,047	824	1,688	1,424	252	189	4,801	3,551
1965	1,941	1,300	1,181	940	1,861	1,585	269	202	5,254	4,027
1966	2,519	1,788	1,417	1,137	2,108	1,770	302	236	6,345	4,932
1967	3,490	2,547	1,614	1,322	2,347	1,976	338	267	7,785	6,112
1968	4,255	3,189	1,899	1,503	2,564	2,134	383	314	9,100	7,140
1969	5,295	3,992	1,998	1,554	2,872	2,421	389	327	10,554	8,294
1970[2]	6,646	5,162	2,291	1,773	3,119	2,627	506	417	12,562	9,979

[1] Contiguous United States.
[2] Prospective.

Note: Totals may not add due to rounding.

Source: Electrical World, Feb. 2, 1970, p. 47.

Patterns of capital expenditures

According to a survey of Electrical World magazine, capital investments in generating facilities are outstripping those for transmission and distribution. It estimates outlays for the year 1970 of $11.6 billion, including $5.6 billion for generation, $2.5 billion for transmission, and $3 billion for distribution. The survey forecasts a capital expenditure for the year 1980 of $18.8 billion, jumping to $27.4 billion in 1985, which would be more than twice that anticipated for 1970. Table 36 gives the figures for the period 1960 through 1985 and shows the rise in capital expenditures from an actual figure of $4.7 billion for 1960 to the estimated $27.4 billion for 1985.

[1] Estimates of Electrical World based on replies to its 66th annual survey of utility construction and expenditures. According to this journal, replies to the survey came from utilities representing 95 percent of the industry's generating capacity and 87 percent of all customers served. See "1970 Construction Spending To Rise 19 Percent," Electrical World, Feb. 2, 1970, pp. 46–50.

TABLE 36.—CAPITAL EXPENDITURES IN THE ELECTRICITY INDUSTRY, 1960–85

[In millions of dollars]

Year	Generation	Transmission	Distribution	Miscellaneous	Total
1960	2,226	715	1,565	183	4,690
1961	2,114	764	1,550	180	4,608
1962	1,693	792	1,593	193	4,271
1963	1,721	837	1,568	230	4,357
1964	1,814	1,047	1,688	252	4,801
1965	1,941	1,181	1,861	269	5,254
1966	2,519	1,417	2,108	302	6,345
1967	3,490	1,614	2,347	380	7,830
1968	4,255	1,899	2,564	383	9,101
1969	5,200	2,200	2,880	472	10,752
1970	5,590	2,500	3,080	500	11,670
1971	6,380	2,500	3,300	540	12,720
1972	6,030	2,400	3,530	580	12,540
1973	5,820	2,400	3,750	620	12,530
1974	6,090	2,700	3,980	660	13,430
1975	6,650	3,000	4,200	700	14,550
1980	9,020	3,900	5,900	900	18,820
1985	14,590	4,700	7,000	1,100	27,390

Source: Electrical World, Sept. 15, 1969, p. 93.

Sources of capital

Until the early 1960's, the investor-owned utilities obtained most of their funds for construction from the sale of new security issues. Since the early 1950's, however, internally generated funds have supplied an increasing share, drawing upon retained earning, depreciation and amortization, and deferred taxes. By 1962, nearly 60 percent of the investor-owned utilities construction funds were internally generated. Amortization and depreciation in 1962 supplied 40 percent of the funds, replacing new debt issues as the most important single source of funds. Table 37 shows the shifts which have taken place in major sources of construction funds since 1950. The overall capital structure of investor-owned systems in 1964 consisted of approximately 53-percent debt, 10-percent preferred stock, and 37-percent common stock and retained earnings.[1]

TABLE 37.—SOURCES OF CONSTRUCTION FUNDS, INVESTOR-OWNED ELECTRIC UTILITIES, 1950–62

[In percent]

Source	1950	1954	1958	1962
SECURITY ISSUES				
Common stock	24.6	17.5	14.5	[illegible].8
Preferred stock	9.5	6.7	6.6	4.4
Debt	33.0	41.6	38.2	22.7
Total securities	67.1	65.8	59.3	40.9
INTERNAL FUNDS				
Retained earnings	7.8	6.2	8.6	14.0
Deferred taxes		4.5	5.9	3.9
Depreciation and amortization	25.1	23.5	26.2	41.2
Total internal funds	32.9	34.2	40.7	59.1
Total	100.0	100.0	100.0	100.0
Total construction funds (in millions of dollars)	1,920	2,950	3,794	3,360

Source: National Power Survey, pt. 1, p. 22.

[1] National Power Survey, pt. 1, p. 19.

Publicly owned systems generally obtain their capital investment funds from power revenues and by selling debt securities in the public market. In the past, such securities were often general credit obligations of the body of government. More recently, according to the Federal Power Commission, the emphasis has been on revenue bonds issued by the utility system itself, payable from revenues alone, and not backed by the general credit of the Government or by a lien on physical properties.[1] Interest on the debt securities of such local agencies are exempt from Federal income tax and in most jurisdictions from State income tax, which gives them a tax advantage over debt securities issued by investor-owned systems.

Only a small portion of the capital requirements for the cooperatively owned systems is obtained from their membership. The remainder is provided largely by long-term mortgage loans from the Rural Electrification Administration. Interest on such loans is authorized by law at 2 percent annually. Under present law, courts have held that the cooperatives are not liable for Federal and State income taxes. Most cooperatives, however, do pay varying State and local taxes.[2]

External financing

Although much of the financing for future construction is expected to come from internal sources, the funds to be raised from external sources will be appreciable. Thus the investor-owned part of the industry will have to go to the financial market to raise some $6.5 billion in 1970. These funds must be raised in a market where interest rates now are between 8¾ and 9 percent, the highest level in the past 100 years.

Besides borrowing at such rates for new plants and equipment the investor-owned utilities soon will face the refunding of bonds that were sold in the 1940's at low interest rates. Such refunding at today's much higher rates will increase the cost of generating electricity.[3]

FINANCING THE ENERGY INDUSTRIES

The oil, coal, natural gas and uranium industries also require capital to expand their production of fuel materials to meet the needs of the electricity industry. While this report has not explored the capital requirements of the fuel industries, it seems evident that companies in this part of the energy business will have to compete with the electricity industry for probably scarce capital funds in the 1970's.

[1] Ibid., p. 24.
[2] Ibid., p. 26.
[3] "1970 Construction Spending To Rise 19 Percent," Electrical World, Feb. 2, 1970, p. 46.

TRENDS IN THE ELECTRICITY INDUSTRY

Both the availability of electricity and its environmental effects are intertwined with prospects for its future growth. At present most experts are predicting a continuation of the historical rate of growth of the industry during the last 30 years of this century. How emerging economic, technical and environmental developments will affect the validity of these projections is far from clear.

PROSPECTS FOR GROWTH—1964

The National Power Survey's projection in 1964 visualized an increasing dependence upon electricity as a source of energy in American life. It also endorsed the philsophy of maximum growth for the electricity industry, to be encouraged by reductions in rates and improvements in service:

> One of the most encouraging aspects of the National Power Survey is the evidence it provides of a commitment by a growing number of power systems in the industry, to a farsighted philosophy of maximum growth encouraged by reductions in rates and steady improvement in service.[1]

The survey projected generation of an estimated 2.8 trillion kilowatt-hours of electricity by 1980, or slightly more than three times that for 1960. The projected increase from 1964 to 1980 was put at 200 percent, in comparison with the estimated rise of about 40 percent in the Nation's population during these 16 years and an increase of perhaps 95 percent in our gross national product.

Implicit in this growth projection is a rise in the per capita use of electricity from about 5,400 kilowatt-hours in 1963 to 10,600 kilowatt-hours in 1980. In comparison with GNP, the increase would be 1.7 kilowatt-hours of electricity per dollar of GNP in 1964 to 2.6 kilowatt-hours in 1980. This projected increase implies more rapid growth than would result solely from population or income growth. The projection assumes a continuation of the marked intensification in the Nation's use of electricity.

CURRENT PROJECTIONS OF ELECTRIC POWER REQUIREMENTS

The Federal Power Commission clearly expects the historical annual growth rate of 7 percent for electric power consumption—with its doubling time of 10 years—to continue through the 1990's. On this basis, electric energy requirements are expected to increase almost fourfold within the next 20 years from 1.52 trillion kilowatt-hours in 1970 to 5.83 trillion in 1990, an increase of 284 percent.[2] During this period, the total peak demand is expected to increase from 277 million kilowatts in 1970 to 1,051 million kilowatts in 1990, an increase of 279 percent. By the year 2,000, it is roughly estimated that the Nation's electric energy requirements will reach 10 trillion kilowatt-hours.

[1] National Power Survey, p. 35.

[2] For the 25-year period 1965-90, the increase would be from approximately 1 trillion to 5.8 trillion, an increase of 450 percent in a quarter of a century.

These projections are based on historic growth rates and growth projections made by electric utility systems and by the staff of the Federal Power Commission. According to the FPC, loads are projected for each of the 48 power supply areas of the contiguous United States taking into consideration such factors as area population growth, anticipated area economic development, trends in family formations, average energy consumption per customer, disposable family income, and innovations in domestic and commercial uses of electricity.

While much of the basic growth in electric loads will be associated with increases in population [1] and general economic expansion, FPC expects such trends will be accentuated by the continual upgrading of electric use by individual customers and by the redevelopment of large segments of metropolitan centers. Modern construction inherently uses more electricity. It is difficult to project how new applications may affect future loads, but future innovations and improvements may include such possibilities as large increases in night lighting of streets, highways, and outdoor recreational facilities, electrification of railways, expansion at urban rapid transit systems, and use of electric industrial vehicles, fleet vans and incity passenger vehicles.

Factors that could accelerate the requirements for electricity-such as a large-scale use of electric vehicles, or that might decelerate the growth, such as increased costs of generation, shortages of fuel or plant, and public reaction to adverse environmental effects apparently are not taken into account.

CURRENT FORECASTS OF GENERATING CAPACITY

In order to meet the estimated 1,050 million kilowatts of power demand in 1990, the electric utility industry will need to install nearly 1 million megawatts of new capacity between 1970 and 1990. Tentative projections of the staff indicate that about 40 percent of all power installed in 1990 will be nuclear power, about 45 percent will be from steam generating plants fired with fossil fuel, 7 percent will come from conventional hydroelectric installations and about 5 percent from pumped storage hydroelectric projects. The remaining 3 percent will be supplied by gas turbines and internal combustion engines, principally the former.

By comparison, for the year 1970, 76 percent of the electricity will come from fossil-fuel, 15 percent from water, 5 percent from gas turbines and internal combustion engines, 3 percent from nuclear and 1 percent from pumped storage.

For the near future, scheduled new additions of electrical generating capacity through 1973, based on scheduled dates of commercial operation as of July 1, 1968, totaled 136.4 million kilowatts, an increase of 50 percent in 5½ years. This increase includes 123.8 million kilowatts in steam-electric plants with 45.7 million of this in nuclear powerplants. By 1972, the annual scheduled additions of nuclear capacity is expected to exceed additions of fossil-fueled capacity.[2]

[1] Increased population, however, would account for only 20 percent of the increased power consumption, Science, Jan. 9, 1970, p. 159.

[2] Testimony of Carl E. Bagge, Federal Power Commission in "Environmental Effects of Producing Electric Power," hearings before the Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, pp. 458-459.

The projected growth of the electric utility industry during these next two decades may entail the construction of about 40 new hydroelectric installations of 100 megawatts or more, approximately 50 new pumped storage hydroelectric installations of 300 megawatts or more and about 90 fossil and 165 nuclear steam-electric plants.

To illustrate what these projections mean for one part of the country, the Northeast Regional Advisory Committee to the FPC estimated the generating capacity needs for 11 Northeastern States.[1]

Between now and 1990, the power industry in these States must build about four times as much electrical generating capacity as the industry has provided thus far in its 80-year history. Based on current practice, this undertaking will require an investment of about $50 billion for generation, transmission and distribution facilities.[2]

Table 38 summarizes the projected electric power requirements and projected forms of power development for the period 1970 to 1990 and includes, for reference, the load-supply situation that existed in 1965.

TABLE 38.—ELECTRIC UTILITY REQUIREMENTS AND SUPPLY,[1] 1965–90

[In millions of kilowatts]

	1965	1968	1970	1980	1990
Energy requirement (trillion kilowatts)	1.06		1.52	3.07	5.83
Peak demand	188		277	554	1,051
Total installed capacity[2]	236.1	277.4	344.0	668	1,261
Hydroelectric capacity	41.7		51.4	68	83
Pumped storage capacity	1.3		3.6	24	65
Internal combustion and gas turbine capacity	4.9		16.2	27	42
Fossil steam capaicty	187.5		261.2	399	562
Nuclear capacity	.7		11.6	[3] 150	509
Capacity dependent on cooling water	188.2		272.8	549	1,071

[1] Excludes Alaska and Hawaii.
[2] Does not add up due to rounding.
[3] The Atomic Energy Commission projection ranges from 120 to 170,000,000 kilowatts.

PRICE AND COST OF ELECTRICITY

A principal cause of the extraordinary growth in use of electrical energy has been a long term downward trend in price. Whether this price trend will continue, however, seems doubtful.

The Federal Power Commission in 1964 proposed a price target of approximately 1.2 cents, or 12 mills, per kilowatt-hour by the year 1980 as the combined average retail price for all residential, commercial, and industrial sales of electricity. Comparable figures were 1.5 cents per kilowatt hour in 1968, 1.7 cents in 1962, and 2.2 cents in 1940.[3] If such a target is reached, the FPC estimated the annual savings to ratepayers at $11 billion per year in 1980. The total electric bill in 1962 was $14 billion; FPC estimated it at $30 billion for 1980, taking into account the $11 billion savings mentioned above. The total annual revenue of the electricity industry exceeded $20 billion in 1969 and is expected to do so again in 1970.

Most of the saving would be achieved through a continuing cycle of lower unit costs of producing and transmitting electricity brought about by larger, more efficient facilities whose low cost electricity would encourage still greater use, thereby creating a cycle of continuously interacting cause and effect.

[1] Vermont, New Hampshire, Connecticut, Rhode Island, Massachusetts, Delaware, New Jersey, New York, Pennsylvania, Maine, and Maryland.
[2] Testimony of John N. Nassikas in "Environmental Effects of Producing Electric Power," op. cit., p. 35.
[3] National Power Survey, pt. 1, p. 5.

Regional variations in the price of electricity for 1962 and projected to 1980 appear in table 39. They range from 8.7 mills per kilowatt-hour for the Northwest to 21.8 mills for the North Central Region in 1962.

Against this background of a historical downward trend in the costs and prices for electricity, the FPC emphasizes that the phenomenal growth in the use of this energy form in the United States is due largely to technological progress that has made electricity one of the best bargains available. The long-term trend of electric rates has been downward even in the face of inflation. To achieve this price goal of 12 mills per kilowatt-hour in 1980, the FPC urged more planning together by the power systems for cost reduction. In particular joint ventures are needed to benefit from the economies of scale of very large powerplants.

> * * * The economies of scale in large generating units coupled with low cost energy transportation suggests that individual power systems should join together in constructing new capacity either through joint projects or by staggering their construction programs.[1]

TABLE 39.—PRICE OF ELECTRICITY BY REGION[1]

[Cents per kilowatt-hour]

Region	1962 actual	1980 projected	Percentage reduction
I. Northeast	2.16	1.51	30
II. East Central	1.42	1.19	16
III. Southeast	1.33	1.00	25
IV. North Central	2.18	1.27	42
V. South Central	1.84	1.16	37
VI. West Central	2.15	1.48	31
VII. Northwest[2]	.87	.86	1
VIII. Southwest	1.73	1.44	17
U.S. average	1.68	1.23	27

[1] Average price per kilowatt-hour sold to ultimate consumers.
[2] Excludes Alaska and Hawaii.

Source: National Power Survey, pt. 1, p. 283.

THE IMPORTANCE OF LOW COST ELECTRICITY

From 1926 to 1968 as the price of electricity declined from an average of 2.71 cents per kilowatt-hour to 1.55 cents, the Consumer Price Index doubled. In terms of constant dollars, the price of electricity in 1968 was less than one-third that of 1926. During this period, the per capital consumption of electricity in the United States increased about eight times, and the total revenue of the electric power industry about ninefold.

The abundance of electricity and its increasingly lower price have become important to American economic well-being. Customer usage has increased more rapidly than declines in unit cost. Accordingly, the electric bill has become an increasing element of the family budget, especially in low income urban areas. The cost of electricity is often a key factor in the planning of industries which are large consumers of

[1] Ibid., p. 3.

electric energy. The use of electricity in metallurgical and chemical processing has continually expanded. Overall, the economic welfare of the Nation is becoming more sensitive to changes in the cost of electricity than would have been true 20 or 30 years ago. Some observers think it is doubtful that any marked increases in the cost of electricity could occur without seriously affecting the growth in electric energy use and, secondarily, adversely affecting the national economy.

COMPONENT COSTS OF ELECTRICITY

The price paid for electricity ultimately must depend upon the cost of generating, transmitting, and distributing this energy commodity. The relative cost of generation, transmission, and distribution based on a composite national average in 1962 for all segments of the industry is shown in table 40. These must not be considered as typical of most utilities for there are likely to be substantial deviations because of the individual differences among systems. For example, transmission costs are less than 4 percent of the total in New York City, but almost 20 percent in the low population areas of northern Minnesota.

Table 41 gives the actual components of power costs for the year 1962 and projections for 1980 and shows the reductions that FPC expected in 1964 would bring the 1980 rate down to 12 mills per kilowatt-hour. The dominant factor in these reductions, it should be emphasized, is the assumed continuing increase in per capita use of electricity with an accompanying increase in efficiency in generation, transmission and distribution. Table 42 presents in more detail the supporting elements which were summarized in table 40. Note that although total 1980 productions costs were expected by the FPC to be 2.3 times those of 1962, the sales are expected to increase 3.1 times—from 780 billion kilowatt-hours in 1962 to 2,433 billion in 1980. Consequently, average production cost per kilowatt-hour would decline from 8.5 to 6.3 mills per kilowatt-hour. Half of this saving would be in fixed charges on investment in generating equipment; 32 percent for lower fuel prices and the remaining 18 percent in operation and maintenance. These savings, the FPC expects, will result from coordinated planning, reduction in unused reserve capacity, use of larger and more efficient generating units, lower fuel prices, lower costs for large bulk movements of fuel and the introduction of nuclear power.

TABLE 40.—TOTAL DELIVERED COST OF POWER—1952

[Composition in percent]

	Fixed charges	Operating expenses	Total cost
Generation	28.2	22.8	51.0
Transmission	7.9	2.0	9.9
Distribution	22.8	16.3	39.1
Total	58.9	41.1	100.0

Source: National Power Survey, pt. 1, p. 26.

TABLE 41.—COMPONENT COSTS OF POWER SUPPLY[1]

[In cents per kilowatt-hour]

	Actual 1962	Percent of total	1980 projected	Percent of total	Reduction	Percentage reduction
Generation	0.85	51	0.63	51	0.22	26
Transmission	.17	10	.17	14		
Distribution	.66	39	.43	35	.23	35
Total	1.68	100	1.23	100	.45	27

[1] Costs such as administrative and general expenses and the annual fixed charges on "General" plant, not directly assignable to these three components, have been allocated thereto on the basis of proportion of direct costs.

Source: National Power Survey, pt. 1, pt. 27C.

TABLE 42.—COMPOSITION OF TOTAL COST OF ELECTRIC POWER, TOTAL INDUSTRY, 1962 ACTUAL AND 1980 ESTIMATED

	1962 actual		1980 estimated	
	Total (billions)	Per kilowatt-what sold (cents)	Total (billions)	Per kilowatt-hour sold (cents)
Production costs (including imports):				
Operation and maintenance expenses (except fuel)[1]	$1.0	0.13	$2.1	0.00
Fuel expenses	1.9	.24	4.2	.17
Fixed charges[2]	3.7	.48	8.9	.37
Total product on costs	6.6	.85	15.2	.63
Transmission costs:				
Operation and maintenance expenses	.3	.04	0.5	.02
Fixed charges	1.0	.13	3.6	.15
Total transmission costs	1.3	.17	4.1	.17
Distribution costs:				
Operation and maintenance expenses	2.4	.31	3.9	.16
Fixed charges	2.7	.35	6.7	.27
Total distribution costs	5.1	.66	10.6	.43
Total cost of power[3]	13.0	1.68	29.9	1.23
Sales to ultimate consumers—billions of kilowatt-hours	773.7		2,433.0	
Number of customers (millions)[4]	60.6		86.8	
Average kilowatt-hours per customer	12,768		28,030	
Total undepreciated investment in electric utility plant (billions)	$66.1		$172.7	
Total investment per customer	$1,091		$1,990	
Distribution investment per customer	$404		$630	

[1] Operation and maintenance expenses include allocated administrative and general expenses.
[2] Fixed charges as used herein include cost of money (return on investment), depreciation and amortization and all taxes including payments made in lieu of taxes. Fixed charges on general plant were allocated to "Production," "transmission" and "Distribution."
[3] Total electric revenues from ultimate customers.
[4] Average for year.

Source: National Power Survey, pt. 1, p. 284.

However, the above cost estimates do not begin to show the effects of added capital investment and increased costs of fuel and operating resulting from requirements placed upon the electricity industry to reduce the emission of wastes to the environment. Thus, Dr. Lee A. DuBridge, science adviser to the President, recently testified before the Senate Committee on Government Operations that the costs of electricity may have to be extended to include total social cost. He said:

It may be that energy consumption is growing so fast in part because the price does not include the full cost to society of producing and delivering it. I believe that efficient power production is just as important as ever to our economic growth, but we delude ourselves and perhaps short-change future generations when the price of electricity does not include the cost of the damaging impact its production imposes on the air, water, and land. If the total social cost of electricity or other products are included in its price, consumers will have the inherent ability to consider the effect of their decisions on the environment.[1]

A PESSIMISTIC RECENT ESTIMATE

There is some pessimism, too, that costs and prices for electricity have reached their low point and will begin to climb. Recently the power engineer Philip Sporn estimated the costs of generation—which are an appreciable part of the total cost of electricity—for approximately comparable nuclear and coal steam-electric plants scheduled for completion in the mid-1970's. These computations are the basis for his pessimistic forecast that nuclear power is retrogressing in its competitiveness with fossil fuels, and that for the immediate future nuclear power can only compete with coal that costs 28 cents per million B.t.u. or more. Table 43 gives the details and shows nuclear power ranging from 6.17 mills to 7.06 mills per kilowatt-hour.

In Sporn's opinion, for many uses in our society, 7-mill electric energy will be too expensive:

Seven-mill nuclear power at the switchboard at 75 percent capacity factor is simply not good enough to heat water, to reduce alumina to aluminum, to smelt ferroalloys, to desalt sea water, and to convert to electricity the many other energy operations our society needs to have done so as to eliminate environmental pollution.

Inevitably, these higher costs bring about the unavoidable reaction in the form of higher rates. Higher rates are antidynamic and growth hindering; they retard the conversion of our energy uses into the electric form.

TABLE 43.—COST OF ELECTRICITY FOR NUCLEAR PLANTS IN 1976 VERSUS COAL PLANTS IN 1975

	Nuclear [1]	Coal [1]	Nuclear [2]	Coal [2]
Fixed charges per year	$28.50	$23.88	$32.56	$27.30
Fixed charges, mills per kilowatt hour	4.07	3.41	4.95	4.16
Fuel charges, mills per kilowatt hour	1.70	[3] 2.19	1.70	[3] 2.19
Operating and maintenance mills per kilowatt hour	.30	.30	.30	.30
Insurance, mills per kilowatt hour	.10		.11	
Total switchboard cost, mills per kilowatt hour	6.17	5.90	7.06	6.65
Nuclear competitive with fuel cost of [4]	[5] 28.1		[5] 29.7	

[1] At 14 percent, 7,000 hours per year.
[2] At 16 percent, 6,570 hours per year.
[3] At 25 cents per million B.t.u.
[4] At 8,750 hours per year.
[5] Cents per million B.t.u.

Note: Capital cost, 1,100 MW Nuclear, $203.5 per kW.; 800 MW Coal, 170.6 per kW.

TECHNOLOGICAL TRENDS IN THE ELECTRICITY INDUSTRY

Several technological trends in the electricity industry may well affect its future organization and operations and also its economic and environmental impacts. Three such trends are the increase in size of electric powerplants and generating units, the expectation that nuclear powerplants will supply much of the electricity by the year 1990, and

[1] Testimony before the Subcommittee on Intergovernmental Relations, Senate Committee on Government Operations, Feb. 3, 1970, p. 10.

the increasing use of extra-high voltage transmission lines. The latter is discussed in the section on transmission. Before discussing the first two, the possibilities of magnetohydrodynamic generation of electricity (MHD) should be mentioned.

Magnetohydrodynamic generation of electricity

Despite recent attention to the advantages of MHD, which if successful could convert substantially more of the heat energy from fuel into electrical energy, present prospects are that it will not come into commercial use much before the end of the century.[1] Therefore its potential effects are unlikely to be seen before the late 1990's.

An increasing size of powerplants

One particularly visible technological trend in the electricity industry has been the increasing size of powerplants. See table 44. From the mid-1920's to the early 1950's the largest steam-electric plants in service had an electrical output of less than 200 megawatts. The first modern 200 megawatt powerplant was placed in service in July 1953. During the late 1950's, 300 megawatts was considered a maximum size. However, by 1961–62, units larger than 300 megawatts captured almost 66 percent of the aggregate generating capacity purchased.

TABLE 44.—MAXIMUM SIZES OF GENERATING UNITS IN THE UNITED STATES

[In megawatts]

Year	Maximum turbine rating—megawatts
1900	1.5
1920	60.0
1930	[1] 208.0
1940	[1] 208.0
1950	[1] 208.0
1956	260.0
1958	335.0
1960	450.0
1963	650.0
1965	[2] 1,000.0

[1] Represents a single unit. More typically, maximum prevailing sizes were 75 megawatts in 1930, 100 megawatts in 1940, and 175 megawatts in 1950.
[2] Under construction.

Source: National Power Survey, pt. 1, p. 14.

At the end of 1968 there were 140 fossil-fueled plants of 500 megawatts and larger, with 45 over 1,000 megawatts in output. The 15 largest of these plants ranged in size from 1,467 to 2,175 megawatts. In terms of individual generating units, at the end of 1968 there were 137 turbine-generator units in service of 300 megawatts capacity and larger. The largest of this group was a 1,028 megawatt unit installed in 1965 in New York City. The first individual unit over 300 megawatts was a 326 megawatt unit placed in service 7 years earlier, in 1958, at Waukegan, Ill. Table 45 shows the very rapid increase in the number and capacity of large units over the 11-year period 1958 through 1968.

[1] In its report "MHD For Central Station Power Generation: A Plan for Action," the Panel on Magnetohydrodynamics of the Office of Science and Technology in June 1969 observed that although MHD could greatly improve the efficiency of fossil fuel powerplants, reducing fuel use by one-third, MHD research had tapered off. It proposed Government funding of such research at a level of about $2 million a year.

TABLE 45.—NUMBER AND SIZE OF LARGE POWERPLANTS PUT INTO OPERATION, 1958–68

Year	300 megawatts and larger		
	Number units placed in service	Total megawatts	Average unit size—megawatts
1958	3	1,060	353
1959	5	1,800	360
1960	8	2,525	317
1961	9	3,180	353
1962	7	2,525	361
1963	10	4,500	450
1964	10	3,625	362
1965	17	7,740	455
1966	[1] 20	8,424	421
1967	26	13,245	509
1968	22	12,274	558
Total	137	60,898	445

[1] 7 of these units were actually installed in prior years and were rerated in 1966.

Source: "Steam-Electric Plant Construction Cost and Annual Production Expenses, 21st annual supplement, 1968." Federal Power Commission report FPC S-199, [illegible], p. x.

How large powerplants will become is an open question. Six years ago, in 1964, the National Power Survey forecast that the unit size for average use in large powerplants pooled systems would be as follows:

TABLE 46.—FORECAST OF POWERPLANT SIZE

Date	Typical unit size megawatts	Maximum unit size megawatts
1970	500 to 600	1,000
1975	600 to 750	1,250
1980	750 to 1,000	1,500

From the standpoint of 1964, the survey saw little economic incentives for individual units above 600 megawatts in size. It identified three factors not previously dominant, that could slow the increase in unit size, and factors that may limit the size to multiunit powerplants. As to unit sizes, these factors are:

(1) Decreasing thermal attractiveness of larger units;
(2) Somewhat decreased economic attractiveness of larger units
(3) The presently indicated lower availability of larger units existing in 1964.

This last factor, according to the FPC, points to the need for improved design in very large plants.

As for factors limiting plant size, the principal limitations appeared to the FPC to be:

(1) The diffusion of stack gases into the atmosphere, and
(2) Limitations on permissible rise in the temperature of rivers and other bodies of water that receive waste heat from powerplants.[1]

The technological trend toward fewer but larger units has implication for the future organization of the electricity industry and the concentration of economic power and influence within it. Because these huge powerplants produce more electricity than most individual power systems can accommodate and because of the large capital in-

[1] National Power Survey, pt. 11, p. 57.

vestment required to build them, joint ventures of various kinds are being organized. This is particularly the case for nuclear power where separate corporations jointly owned by participating utilities are used to limit the liability of the parent companies should an accident occur with the nuclear plant causing liabilities for damage and injuries exceeding the coverage of commercial liability insurance and Government indemnification under the Price-Anderson modification to the Atomic Energy Act.

As the size of individual generating units has increased, so has the tendency to place several units at one site. Thus the Office of Science and Technology expects that most of the new generating capacity in the next 20 years will come from some 250 huge powerplants of 2,000 to 3,000 megawatts output each. In comparison, there are some 3,000 powerplants in existence today. A powerplant of 3,000 megawatts will produce enough electricity for a city of 1 million people. In principle these mammoth powerplants not only will produce lower cost power than their smaller and less efficient predecessors, but they will also produce less pollution per kilowatt-hour. However, because so much power is generated at one place, the total volume of wastes discharged at one point will be quite large and if uncontrolled could overwhelm the surrounding environment.

The trend toward nuclear power

The forecasts of the Federal Power Commission that nuclear power will provide 40 percent of all utility generated electricity by the year 1990 and as much as 60 percent by the year 2000 depends upon commercial demonstration, acceptance and application of the breeding reactor. Nuclear powerplants being built now and those into the 1980's will not possess the mechanical ability to convert certain kinds of uranium and thorium into useful nuclear fuel as a byproduct of power generation, and thus at best can use only a few percent of the energy available in uranium and thorium ore deposits.

If the breeding reactors are to come into use during the later 1980's, utilities will have to order them at least 6 years earlier, in the early 1980's. It seems reasonable to expect the utilities to want several years actual experience with prototype breeder nuclear power reactors before deciding to buy breeder reactors, which means any prototypes would have to come into service in the late 1970's. Assuming once again a 6-year period to design, build and bring a prototype breeder into operation, the commitments to do so must be made in the early 1970's. Whether the utilities are or will be ready to make such a technical financial commitment within the next few years remains to be seen.

As for the current state of commercial nuclear power, the year 1968 marked the beginning of the second decade in the operation of nuclear reactor steam-electric generating units. It also marked the first full year of operating experience of two of the larger, commercial type, light-water reactor installations, the 600-megawatt Connecticut Yankee plant and the 450-megawatt San Onofre plant in southern California. Both plants began commercial operation on January 1, 1968. They were designed and built under the so-called modified third round of the Atomic Energy Commission's power demonstration program. Both installations were subsidized by the AEC on the

research and development phases prior to construction. Likewise, both plants have a 5-year waiver from AEC on their fuel use charges.

The FPC lists 80 nuclear-powered units in 58 plants totaling approximately 66,000 megawatts that are either (1) in preliminary or test operation, (2) under actual construction, or (3) on order for commercial operation during the 9-year period, 1969 through 1977. These 80 units, varying in size from 450 to 1,175 megawatts, constitute the so-called second and third generations of power reactors. Three of these units were ordered during the first 8 months of 1969 and 17 in 1968. The other 60 units were ordered during the period 1963 through 1967. Test operation of the Oyster Creek plant, the first of the 500-megawatt class to be completed, was begun in the summer of 1969 after many delays. This plant at Jersey Central Power & Light Co. and several others are expected to begin commercial operation during 1970.[1]

[1] "Steam-Electric Plant Construction Cost and Annual Production Expenses," op. cit., p. xiii.

Environmental Effects of Generating Electricity and Their Economic Implications

The generation of electric power inevitably must affect the environment. Wastes are generated and they must go to some place. Whether the effects of the wastes are beneficial, tolerable, undesirable or dangerous are value judgments determined by society.

In achieving a balance of interest between the users of electricity on the one hand and the users of the environment on the other, there is reason to avoid the two extreme positions that hold:

The environment should not be available to wastes from generation electricity, or

Powerplants may be constructed and operated without regard to their environmental effects.

In this section, the principal wastes of the electricity industry are identified, their effects briefly described, current regulation of such wastes summarized, and present technology for control is described. Cost information is also mentioned.

This section draws heavily upon the report of the Energy Study Group of the Office of Science and Technology on the siting of steam-electric powerplants and upon recent hearings of the Joint Committee on Atomic Energy and the Senate Committee on Government Operations.

CONVERSION OF HEAT ENERGY INTO ELECTRICITY

In a steam-electric powerplant, the heat energy released by burning fuel or fissioning nuclear materials heats water which turns to steam. The steam expands through a turbine, then flows to a condenser where it is condensed back into water which is returned to the boiler or the reactor to start the cycle again. The turbine turns a generator which produces the electricity. Ideally for every 3,413 British thermal units of heat energy released from the fuel, 1 kilowatt hour of electricity should be sent out from the plant.[1] However, present energy conversion technology is far from ideal. Depending upon its age, a steamplant may require from 19,000 to somewhat less than 9,000 B.t.u.'s of heat energy to generate 1 kilowatt-hour of electricity. The best heat rates [2] for 1968 ranged from 8,654 to 8,876 B.t.u.'s kilowatt-hour for the most efficient units in the country.[3] New thermal efficiency of powerplants, or efficiency, as we will call it, is the quotient of the plant electrical output, expressed in B.t.u., divided by the heat input in B.t.u. For technical reasons the best efficiency attainable with present steam powerplant technology is 40 percent. At this efficiency, 8,533 B.t.u.'s heat energy must be supplied for each kilowatt hour of electricity sent out. Present nuclear powerplants are less efficient. Those being built today are unlikely to have an efficiency better than 33 percent, meaning that 10,342 B.t.u.'s must be supplied for every

[1] 1 B.t.u. of heat energy will raise the temperature of 1 pound of water 1° Fahrenheit.
[2] The heat rate is the number of B.t.u. needed per kilowatt hour.
[3] Electrical World, Nov. 10, 1969, p. 26.

kilowatt-hour. The heat rates for the Vermont Yankee nuclear powerplant in New England, for example, is 10,560 B.t.u.'s per kilowatt-hour.

The amount of heat required by a steam-electric plant to generate a kilowatt-hour of electricity depends very much upon the temperature, pressure, and moisture content of the steam, which in turn depends upon the ability of materials to retain their strength in fireboxes and boilers when exposed to very high temperatures and to corrosive hot combustion gases. The higher the temperature and pressure of the steam and the less its moisture, the more heat energy is carried to the turbine by each pound of steam and the greater is the plant efficiency. The relative thermal inefficiency of nuclear powerplants derives from the lower temperature, pressure, and higher moisture of their steam. The technical reasons for these conditions are unlikely to be resolved with the type of nuclear powerplants now being sold to the utilities. More efficient nuclear plants are expected, but they are unlikely to come into operation until the mid or later 1980's.

The prospects of marked further improvements in powerplant thermal efficiency will have to await the outcome of current technical efforts to develop new energy conversion processes such as magnetohydrodynamics, electrogasdynamics and thermionic processes.

WASTES FROM STEAM-ELECTRIC GENERATING PLANTS

Electric powerplants that use the fossil fuels—coal, oil or gas, or nuclear fuels, all produce excess heat energy. Presently this heat is regarded as a waste to be disposed of to the environment. Fossil-fuel plants also produce solid and gaseous wastes that in certain quantities and concentrations are regarded as air pollutants. Nuclear plants do not omit wastes from combustion, but do produce some radioactive wastes that are routinely discharged into the air or water and may be regarded as pollutants if the releases exceed regulatory limits. The validity of limits set for emission of waste heat, some combustion wastes and radioactive wastes is being questioned by some scientists at this time.

WASTE HEAT

The heat energy released by burning fuel or fissioning atoms that does not leave a generating station as electricity must be discharged to the environment. It cannot be stored or kept within the powerplant. The air and water, in essence, are used as a sink for the waste heat. For a steam-electric powerplant operating at an efficiency of 40 percent, for each 100 B.t.u. released from the fuel, 60 B.t.u. must be thrown away; with an efficiency of 33 percent, for every 100 B.t.u. released, 67 must be disposed of. Thus from 60 to 67 percent of all the fuel consumed in a central powerplant ultimately serves only to heat up the air and water in the vicinity of a powerplant. It brings no income to the utility and may require capital investment and operating costs to disperse it in ways acceptable to the Government.

Removal of waste heat from a powerplant

For all steam-electric powerplants now built or contemplated, most or all of the excess heat which may either flow back into a river or other parent body of water or circulate through equipment that transfers the heat to the air is carried from the plant by water. For a

conventional fossil-fueled plant, about 85 percent of the waste heat goes out in the cooling water with 15 percent going up the stack as hot flue gas. For a nuclear plant, virtually all of the waste heat, except for about 5 percent emitted to the air from hot surfaces, is in the cooling water. A modern fossil-fueled powerplant that requires 9,000 B.t.u. per kilowatt hour of electricity sent out would discharge 4,237 B.t.u. of waste heat for each kilowatt hour. A less efficient nuclear powerplant with a heat rate of 10,342 B.t.u. per kilowatt hour would discharge 6,400 B.t.u. of waste heat, almost half again as great, than for the fossil-fuel. This is the basis for the statement that a nuclear powerplant will discharge 50 percent more heat into the water than a conventional plant.

Many steam-electric plants use the once-through cooling system to dissipate the waste heat. In such a system the cooling water is taken from a river, lake, reservoir, or the sea, and passed through the powerplant whence it returns with an increased heat load and higher temperature. Once-through cooling is preferred at sites where there is an adequate supply of water and its use for cooling does not violate Federal or State water quality standards. This system has the advantage of low cost, minimum consumption of water and minimum intrusion upon the environment. If water is scarce or if compliance with water quality standards so requires, the waste heat from the cooling water can be transferred to the air by one or more processes.

The amount of cooling water required depends upon the heat rate of the plant and the permissible rise in water temperature. For an average fossil fueled plant with a heat rate of about 10,000 Btu per kilowatt-hour, and a temperature rise of 15 degrees Farenheit, the required flow is approximately 1.5 cubic feet per second for each megawatt of electrical capacity. At full load, this is equivalent to about 40 gallons per kilowatt-hour. A modern, more efficient plant would require a flow of about 1.5 cubic feet per second per megawatt for a 15-degree rise, equivalent at full load to about 30 gallons per kilowatt-hour. For a nuclear plant, the flow would be about 2.0 cubic feet per second per megawatt for a 15-degree rise. At full load this would come to about 55 gallons per kilowatt-hour.

In designing a power plant, the engineer seeks the most favorable economic balance between temperature rise in the cooling water, flow of the water, and size and cost of the equipment. With present technology he can choose a temperature rise between 12 to 27 degrees Farenheit. Temperature rises of less than 12 or greater than 27 degrees are considered impracticable from an engineering standpoint. If, for technical or regulatory reasons, it is desirable to keep the temperature of the cooling water below certain limits as it returns to its parent supply, unheated water can be mixed in to dilute the heat and lower the temperature.

HEAT AND WATER QUALITY

Discharging waste heat from steam electric plants into the waterways does not directly affect the public health. There is no danger of injury to persons. On the other hand, the waste heat can markedly change the quality of the water for further use and can drastically affect the marine life in the water.

What the specific effects from waste heat are remains a controversial matter. Some observers see only undesirable effects upon the quality

of the water and the plant and animal life it sustains. Others see beneficial effects from waste heat. Depending upon the part of the country and the kinds of water life involved, effects of waste heat can range from fish-kills on one hand to speeding lobster growth on the other.

What follows is intended to briefly summarize the less than desirable effects of too much waste heat in a given body of water. It draws heavily upon the report of the Energy Policy Staff of the Office of Science and Technology.

Effects upon water life

The most pronounced effects of waste heat in the waters appear to be upon water life.

As a rule of thumb, the biochemical processes of aquatic life, including the critical rate of oxygen utilization, double for each 18 degree Fahrenheit rise in temperatures up to 86° to 95°. However, as water temperatures rise, the water can hold less oxygen in solution. Thus the potential supply of oxygen in the water diminishes with higher temperatures as the need for oxygen increases.

Up to a certain point, an increase in water temperature can cause more rapid development of eggs, faster growth of spat, fingerlings or juvenile fish and larger fish. Beyond that point, the hatch will be reduced and mortalities in the development stages will be higher. The temperatures at which maximum development occurs at each stage of the life cycle varies with the species. Over a period of several generations the composition of species in water bodies affected by waste heat can be expected to change if the temperature is changed, even though the change be small.

Even where a temperature change is not directly damaging to the development of desirable species, an increase is usually found to stimulate the more rapid development of less desirable or undesirable species.

While fish are generally available in the discharge areas for waste heat, sometimes in greater numbers than elsewhere, it is often found that an increase in temperature results in a loss of the more desirable species since they are unable to compete successfully for food, breeding areas or their lives. A warmer temperature is also considered to increase the occurence of disease in fish populations.

A particular problem exists for migratory fish since changes in water temperature are apparently important to some species as the stimulator of migratory activity. Changes in the normal times for migration triggered by heated water may put the fish at an environmental disadvantage later in their migratory cycle and adversely affect reproduction. Since the ability of each species to acclimate to changes in water temperature is different, each situation should be considered individually by fishery biologists.

On the other hand, techniques for forecasting ecological effects of heated waters are not as well advanced as the ability to forecast the patterns of heat dissipation in the receiving waters. We apparently know more about how and where the heated effluents from a powerplant will flow than we do about their specific effects in a particular situation.

Physical effects

Any increase in temperature of water because of waste heat will result in increased evaporation and a consequent reduction of available supply and an increase in the concentration of the minerals already present in the water, which do not leave with the evaporating vapors. While not ordinarily a problem, if a stream of water flows through a number of cooling cycles each with a loss from evaporation, a measurable increase in solids may result.

In northern climates, the discharge of heated water will tend to reduce ice cover, at least locally, and thus improve water quality by keeping the surface open to absorb oxygen from the air. The added heat may also result in local fogging on the water and adjacent land areas.

An increase in temperature may also make the waters more desirable for swimming and water sports if the normal temperatures are so cold as to limit use. If the water is already warm, however, further increase in temperature can reduce its recreational value.

The addition of waste heat to bodies of water may also reduce the value of the water for industrial cooling in those places where the local temperature has been increased substantially.

REGULATION OF WASTE HEAT IN WATER

Although water quality standards had previously been adopted by some States and interstate bodies, a major impetus to setting such standards was the Water Quality Act of 1965. That act encouraged the States to establish water quality standards for interstate streams and coastal waters by June 30, 1967. If the States failed to do so, the Secretary of the Interior was authorized to establish such standards. All 50 States have developed water quality standards and have submitted them to the Department of Interior for approval.

Provisions of the Water Quality Act

The act requires that the standards be such as to protect the public health or welfare and to enhance the quality of water. In establishing the standards, consideration is to be given to the use and value for public water supplies, propagation of fish and wildlife, recreation, agriculture, industry and other legitimate uses.

As interpreted by the Federal Water Pollution Control Administration of the Department of the Interior, the standards to be established include water use classifications, criteria to support these uses, and a plan to implement and enforce the criteria. The criteria include the quality characteristics of a physical, chemical or biological nature demanded by aquatic life, industrial process, or other intended uses. For streams expected to have more than one use, the criteria of the most sensitive use would govern in establishing standards. Thus, in most cases, the criteria applicable to fish and other aquatic life would be controlling.

State thermal criteria for waste heat

Pursuant to the act, all States have submitted water quality standards. The standards for all States and other jurisdictions have been approved by the Secretary of the Interior, although some approvals have been with reservations. Many of the reservations relate to temperature criteria.

The temperature criteria is water quality standards are established on the basis of the proposed uses of the water. Generally, maximum permissible temperature and maximum changes in temperature constitute the criteria. Some States have specified maximum rates of change in temperature. Several State standards provide for varied criteria depending on the time of year. Some waters are so designated as to allow no change from the natural conditions. In such cases, the limitations are usually determined by the requirements of fisheries.

Most States have established 68 degrees Farenheit as the maximum allowable temperature and from 0 to 5 degrees as the maximum allowable change in temperature for streams with cold water fisheries. For warm water fisheries, the maximum allowable temperatures are generally in the range of 83 to 93 degrees and the maximum allowable rise in the range of 4 to 5 degrees.

Turkey Point, a departure in Federal regulation

In Florida south of Miami, the Florida Power and Light Company has two large conventional steam-electric power plants and is building two large new nuclear power plants. The cooling waters from the new nuclear plants is to flow through a canal 6 miles long to mix with the waters of Card Sound, an adjunct to Biscayne Bay. The heated water from the canal presumably will meet a Dade County temperature limit of 95 degrees Ferenheit.

In February 1970, the Department of the Interior requested the Justice Department to take legal action to block construction of the canal. It asserted that the canal system with the proposed 150 percent dilution of the cooling water would not meet the temperature limits agreed upon by the State and Federal conferees at a meeting called at the request of Governor Kirk of Florida. Out of this meeting came a recommendation of 90 degrees as maximum temperature for water discharged from the canal.

The utility has argued that waste heat must be discharged to the Bay for other means of dissipating the heat are not feasible.

On March 13, 1970, the Justice Department filed suit in the U.S. District Court for the southern district of Florida to stop present and future thermal pollution of Biscayne Bay. Attorney General John N. Mitchell said the suit alleges that the heated water now being discharged from the present two powerplants is rapidly ruining marine life in the Bay, including an area encompassed by the Biscayne National Monument, and that the damage will be even greater when two planned nuclear powerplants are installed at the site.

The Government also filed a motion for a preliminary injunction. It asked that the powerplants be permitted to operate but to modify its operations which result in thermal pollution. It also asks for submission to the court within 45 days of a plan to eliminate the destruction of the natural environment by the powerplant operation; and a halt to construction to the canal.

BYPRODUCT USE OF WASTE HEAT

Ideally the excess heat energy from a steam electric powerplant should be put to productive use in industry, agriculture, dwellings or other places where large amounts of low-grade heat may be useful. To do so would reduce the waste heat discharged directly to the environ-

ment and save the additional fuel that otherwise would be consumed to supply such heat. Sale of byproduct waste heat might even become a souce of income for the utilities. The chemical and petroleum industries, for example, require large amounts of heat as does the desalting of water. Proposals have been made to use heated waters from powerplants in agriculture and aquaculture. However the benefits, of such applications, their technical and economic feasibility remain to be demonstrated.

The tendency towards building large powerplants outside of the cities and the impracticability of transporting low-grade heat for long distances will require new innovations in business and industry to make the use of waste heat as a byproduct an attractive alternative to discharging it to the environment.

DISSIPATION OF WASTE HEAT TO THE ENVIRONMENT

As noted earlier, the simplest and least expensive, and the traditional method for disposing of excess heat from a steam electric powerplant is to pump water from a river or some other body of water through the powerplant to pick up and carry away the waste heat. The heated waste water mixes with its parent and its burden of heat energy ultimately is transferred to the air by evaporation, conduction, and radiation. Depending upon the amount of waste heat and the characteristics of the receiving waters, the water temperatures in some places may exceed limits set in water quality standards. In such instances, some or all of the waste heat from a powerplant may have to be transferred directly to the air. For these, the cooling water from the powerplant is circulated through a man-made cooling pond or lake, or thorugh cooling towers.

Cooling ponds and lakes

The electricity industry makes wide use of cooling ponds in the Southwest and Southern States where available water supplies may not be wholly adequate to dissipate the waste heat. The extensive land areas necessary for the ponds and their drainage areas are available in these parts of the country at relatively low cost, and the low humidity in the Southwest promotes more effective transfer of waste heat from the pond to the air.

In many instances, cooling ponds and lakes may be quite large. Approximately 1 acre of pond plus 10 acres of drainage area to supply water for the pond is needed for each megawatt of generating capacity. Such ponds may be used for public benefits including water supply, flood control, recreation, and enhancement of fish and wildlife values.

Cooling ponds require a flow of water to replace that lost through evaporation. The loss is equivalent to about 1.5 percent of the flow of cooling water from the powerplant.

Where land is available at low costs, cooling ponds may be the least expensive alternative to direct discharge cooling. Capital cost estimates for cooling ponds and associated dams and structures range from $2.50 to $5 per kilowatt of generating capacity, and in some conditions $6 to $10 per kilowatt.

Cooling towers

Waste heat can be transferred to the air through two types of cooling towers. In the evaporative type, the water to be cooled falls over exposed surfaces within the tower and gives up its heat by evaporation. In the dry type, the water is pumped through the giant equivalent of an automobile radiator and gives up its heat by air convection.

Evaporative cooling towers

The performance of a cooling tower depends upon the movement of air through the structure to carry away the evaporated water. In some cooling towers, mechanical fans draw air through the structure, in others the flow of air depends upon natural air movements, or convection.

Environmental effects of evaporative cooling towers.—The mechanical cooling towers discharge large amounts of water vapor near the ground. Also droplets of water, or "windage" may be carried from the tower by air currents. Windage is troublesome because it may contain chemicals that are added to prevent biological fouling of the cooling system, chemicals resulting from corrosion or structural deterioration, and minerals that have become concentrated within the system. In some weather conditions, mist, fog or ice may result from these cooling towers.

As an alternative to the mechanical cooling tower, the natural draft tower discharges its moisture considerably higher off the ground. Such a tower for a large powerplant may rise as high as a 30-story building and measure more than a block in diameter. They are certainly a dominant feature of a power station and may be visible for miles. Some people consider them esthetically undesirable in certain locations.[1]

The windage effects of cooling towers would be aggravated were sea water to be used as the cooling water. With solids present in the amount of 35,000 parts per million, the salt in the windage could cause corrosion damage to adjacent structures and equipment and to nearby land.

Water requirements.—The water lost by evaporation within a cooling tower amounts to about 20 gallons per-kilowatt of generating capacity per day for an average steam electric plant, and about 13 gallons for one of high efficiency. A 1,000 megawatt nuclear powerplant, with its lower efficiency, would require about 20 million gallons of makeup water a day, in comparison with 14 million for a comparable fossil plant.[2]

Water pollution from cooling towers.—The evaporation of water in a cooling tower serves to build up a concentration of minerals present in the source of cooling water, and also to concentrate chemicals and solids from other sources. For technical reasons, the concentration cannot be permitted to increase without limit. Therefore part of the cooling water is routinely drained off and replaced. This is known as "blow-down." The concentration of minerals and chemicals in the blow-down water may exceed water quality standards. This waste water must either be processed to remove enough of the mineral and chemical contents to bring the effluent into compliance, or be diluted enough for this purpose.

[1] Cooling tower applications and technology are reviewed in detail in the Federal Power Commission report "Problems in Disposal of Waste Heat From Steam-Electric Plants," published in 1969.
[2] "Cut pollution at what price?" Electrical World, Jan. 19, 1970, p. 32.

Water brought into a cooling system to make up for evaporation may typically contain 50 parts per million of solids. The concentration within the cooling circuit may be held at 700 parts per million, meaning that blow-down waters contain this concentration.

Dry cooling towers

In principle the dry cooling tower should avoid the problems of fogging, mist, and icing of the evaporative types, and has no routine water loss. It discharges only dry heat to the air. Dry towers may either be mechanical, with a forced air draft, or natural draft. Dry towers are not able to cool the water as much as a wet or evaporative tower, which reduces the powerplant efficiency and requires more fuel for each kilowatt-hour of electricity generated.

Dry cooling tower technology has yet to be demonstrated in the United States for large steam-electric plants. The largest natural draft tower in operation today is one at a 120-megawatt powerplant in England. This tower was built in 1962 by the Central Electricity Generating Board, primarily to obtain comparative investment and performance data. It is reported that the performance of the tower has been satisfactory.

Environmental effects of dry cooling towers.—At present the environmental effects of discharging large quantities of dry heat from such cooling towers are not known.

Costs of cooling tower

The costs of various types of cooling systems depend upon the design of the system and the site conditions. The Federal Power Commission has estimated the ranges of costs based on data from electric utilities. Table 47 summarizes the estimated investment cost for evaporative cooling towers.

TABLE 47.—COMPARATIVE COSTS OF COOLING WATER SYSTEMS FOR STEAM-ELECTRIC PLANTS

Type of system	Investment cost, dollars per kilowatt	
	Fossil fueled plant [1]	Nuclear fueled plant [1]
Once through [2]	2.00-3.00	3.00-5.00
Cooling ponds [3]	4.00-6.00	6.00-9.00
Wet cooling towers:		
Mechanical draft	5.00-8.00	8.00-11.00
Natural draft	6.00-9.00	9.00-13.00

[1] Based on unit sizes of 600 mw and larger.
[2] Circulation from lake, stream, or sea and involving no investment in pond or reservoir.
[3] Artificial impoundments designed to dissipate entire heat load to environment. Cost data are for ponds capable of handling 1,200-2,000 mw of generating capacity.

Source: Federal Power Commission. "Problems in disposal of waste heat from steam-electric plants." A staff study supporting the Commission's 1970 National Power Survey. 1969, p. 15.

An operating cost common to all cooling systems is the cost of power used to pump water through the systems. For cooling towers, a greater pumping effort is required, with the additional power required being equivalent to one-half percent or more of the plant output. Power to drive the fans in a mechanical tower account for upward of 1 percent of the plant output. Annual operating and maintenance costs for cooling tower systems, exclusive of the costs of power, are equivalent to 1 or 2 percent or more of the capital investment in the cooling system.

According to Federal Power Commission estimates, the use of evaporative cooling towers rather than the once-through cooling could increase the cost of generating power as much as 5 percent. Also cooling towers ordinarily reduce turbine efficiency so that most estimates indicate a 1-percent capacity penalty chargeable against plants using wet cooling towers.

For a specific example, the cooling towers for the Monticello nuclear powerplant in Minnesota were recently reported to add $5 million to the capital costs and $1.9 million annually to the operating cost. At an 80-percent operating factor, the cooling towers thus would add about one-tenth of a mill per kilowatt-hour to the estimated generating cost of 7 mills per kilowatt-hour for the plant.[1]

Investment costs for dry-type cooling towers are largely conjectural because of limited experience with them. The FPC thinks a price range of $25 to $28 per kilowatt for mechanical draft and $27 to $30 per kilowatt for the natual draft appear to be reasonable. With these costs, dry-type cooling does not compare favorably with other types of cooling at places where adequate water supplies are available. Also, the plant electrical output may be from 6 to 8 percent less than it would be with on-through water cooling, which would increase the cost of power.

In one recent estimate, cooling ponds would be expected to increase generating costs by perhaps 15 percent, and dry towers perhaps 30 percent, with evaporate towers in between. In terms of billings to the public, installation of those heat dissipation methods could increase the retail[2] rate from 5 to 10 percent.

While such an increase probably would be accepted by the public, industries that use large amounts of electricity at low rates would be more seriously affected should the addition of such measures add 1 to 2 mills per kilowatt-hour to a price of 5 to 10 mills. Such an increase could have a significant effect on the prices of products that require large amounts of electricity to manufacture.

Cooling water requirements

A very practical question is how much water may be affected by waste heat from large steam-electric plants?

The Federal Power Commission expects that 59 new fossil-fueled plants or additions to existing plants of 500 megawatts or more, comprising 81 units and totaling 52,000 megawatts, will go into service during the years 1967 to 1973. An additional 41 nuclear plants or additions to existing plants comprising 57 units, totaling 42,000 megawatts, also are scheduled to go into service in that period.

The combined cooling water discharges from these 138 units with almost 100,000 megawatts of capacity will be a substantial addition to the waste heat discharged to the Nation's waters.

Looking ahead to 1990, the FPC estimates a total of 492 plantsites will be in use for large steam-electric installations. Of these, 255 will be new sites. Some 292 of the total number of sites would be for fossil-fueled plants and the remaining 200 for nuclear power. Most of the new plants are expected to be in the 1,000- to 4,000-megawatt size range, with the largest site approaching 10,000 megawatts, The total capacity at the 492 sites by 1990 would be about 1 million megawatts.

[1] Nucleonics Week, Mar. 5, 1970, pp. 4, 5.
[2] "Cut Pollution at What Price?" op. cit., p. 33.

The total estimated fresh water withdrawal in 1990 for these powerplants is estimated by the FPC to come to 300,000 cubic feet a second. Although this would be equivalent to one-sixth of the total annual rate of runoff of streams in the United States, much of the water can be used again at several sites along a particular river.

AIRBORNE WASTES FROM ELECTRIC POWERPLANTS

Future plans for generation of electricity in powerplants that burn fossil fuels are likely to be critically affected by the need to control emission to the air of wastes that have undesirable effects.

At the outset, one should note that powerplants are not the only source of air pollution. The combustion of fossil fuels for all purposes produce some 142 million tons of air pollutants, as shown in table 48. Automobiles and other forms of transportation discharge nearly 60 percent of the total emissions. However transportation is not a significant source of sulfur oxides because the fuels used are low in sulfur content. Stationary fuel combustion sources account for 75 percent of the sulfur oxides, while refineries, smelters, acid plants, and similar processes emit the remainder. Fossil-fueled powerplants which produce over 85 percent of the electricity generated in the United States in 1966 discharge almost 50 percent of the sulfur oxides, 25 percent of the particulates, and about 25 percent of the nitrogen oxide emissions.

TABLE 48.—SOURCES OF AIR POLLUTION

[In millions of tons annually (1965)]

	Carbon monoxide	Sulfur oxides	Nitrogen oxides	Hydrocarbons	Particulate matter	Totals
Motor vehicles	66	1	6	12	1	86
Industry	2	9	2	4	6	23
Powerplants	1	12	3	1	3	20
Space heating	2	3	1	1	1	8
Refuse disposal	1	1	1	1	1	5
Total	72	26	13	19	12	142

Source: "Considerations affecting steam powerplant site selection." Op. cit., p. 29.

Sulfur oxides

Recent projections estimate that by the year 1980 some 48 million tons of sulfur dioxide would be released to the air annually, assuming that control measures are not applied. Of this, 36 million tons would come from powerplants in comparison with 12 million tons in 1966.

Effects of sulfur dioxide

Gaseous sulfur dioxide from burning fossil fuels may later form droplets of sulfuric acid in moist air. These droplets are potentially injurious to the respiratory system. When combined with small particle pollution and stagnant air, the resulting air pollution may lead to the kinds of injury experienced in Donora, Pa., New York, and London when severe pollution episodes occurred. On the other hand, the precise quantitative biological effects of sulfur dioxide are not fully known, which complicates the setting of air quality standards. Regardless of specific biological effects, it appears generally agreed that sulfur dioxide air pollution can effect persons suffering from lung ailments of bronchitis, emphysema, or cancer.

The acid mists also may damage property and vegetation. In combination with other pollutants, for examples particulates, sulfur oxides have been shown to exhibit synergistic effects and produce results several times more severe than from comparable exposure to either pollutant alone.

Regardless of the completeness of present scientific information about the biological efforts of sulfur dioxide, the public regards it as a pollutant to be controlled.

Regulation of sulfur oxides

The regulation of sulfur dioxide and other air pollutants is primarily the responsibility of State, local, and regional agencies, backed up by the Department of Health, Education, and Welfare.

Federal legislation.—Pursuant to the Clean Air Act (Public Law 90-148), DHEW administers Federal aid grants to establish and maintain regional, State and local air pollution control programs. DHEW also is establishing air quality control regions, with a completion target date of September 1970. It has released air quality criteria for carbon monoxide, photochemical oxidants, and hydrocarbons, and also control techniques for stationary sources of emissions of carbon monoxide, nitrogen oxides, hydrocarbons and organic solvents. The Department has reported to Congress that national emission standards for stationary sources, which would include steam-electric powerplants, is not in the best interest of pollution abatement. Rather, DHEW favors national air quality standards with local, State, or regional agencies responsible for implementing them, and with national emission standards limited to application to new installations.

The act authorizes DHEW to recommend and establish standards if sufficient local standards are not adopted and in an emergency to enjoin the emission of contaminants.

State legislation.—State air pollution control laws empower State and local air pollution control agencies to promulgate standards for regulating sulfur compounds in the air. Typically, States enacting or amending air pollution control laws authorize the creation of a State air pollution control agency, which is instructed to issue rules and regulations pertaining to air quality and, in some instances, to issue sulfur emission standards and limits for sulfur content of fuels.

State regulation.—Rules and regulations of State air pollution control agencies have become increasingly specific for sulfur control. State regulations generally contain a sulfur dioxide emission limit for individual sources, using a figure of 2,000 parts per million by volume of sulfur dioxide as a limit for existing sources. This standard appears directed more toward regulation of sources such as sulfuric acid plants that may emit sulfur dioxide as a byproduct of manufacturing rather than from the combustion of fuel. Recent legislation in South Carolina, New York, Missouri, and other States, has set variable emission requirements for combustion sources. Consequently an electric power station may have quite a different sulfur dioxide emission limit in many jurisdictions than an industrial processing plant, and for electric powerplants there may be a wide variation in the emission limits prescribed.

Sulfur dioxide emission standards are being supplemented, and in some places preempted, by regulations limiting the sulfur content of fuels. This approach is more certain and less expensive to administer.

Current enactments set different fuel limits according to use. Fuel for steam and electric stations, heating and industrial may have different limits. Limits are usually expressed in terms of a maximum percentage of sulfur by weight, and there is little uniformity amongst them. Some authorities have set the maximum as low as 1 percent and by 1970 it may be as low as 0.37 percent. According to the National Coal Policy Conference, in every instance the sulfur limit set is significantly lower than the sulfur contained in the coal previously burned within the jurisdiction.

Action in California.—Perhaps the most severe limitation upon sulfur dioxide is to be found in California. There the State's environmental quality study council has recommended a moratorium on fossil-fueled powerplants. The Orange County Board of Supervisors subsequently voted against two 790-megawatt units at Huntington Beach. The Los Angeles Air Pollution Control Board has indicated it will not approve further applications for fossil-fueled powerplants.[1]

Technological alternatives to reduce sulfur dioxide emissions

Five technological approaches may be used, singly or in combination, to keep the sulfur dioxide emission from a steam electric powerplant within limits of air quality standards. These are to:

(1) Use fuels of low natural sulfur content.
(2) Remove or reduce the sulfur in fuels.
(3) Remove the sulfur dioxide from stack gases.
(4) Improve the combustion process.
(5) Disperse the stack gases sufficiently that the sulfur dioxide at ground levels stays within air quality limits.

Use of low sulfur fuels.—The ideal fuel of low sulfur content is natural gas, which explains why some air pollution control authorities specify the use of natural gas by steam electric plants. Some residual fuel oils also may have a naturally low sulfur content, depending upon their origin. The residual oils from Africa are the lowest in sulfur. Some coal deposits also are low in sulfur, but limited supply and strong competition for nonfuel uses greatly limits their use.

While the use of low sulfur fuels may provide some temporary relief from air pollution, in the long run ways must be found to reduce the sulfur content of fuels before they are burned and to remove enough sulfur dioxide from powerplant emissions to stay within air quality limits.

One noticeable result of the specification of sulfur emission standards has been to accelerate a trend away from coal into gas and residual fuel oils. According to the Office of Oil and Gas of the Department of the Interior, the use of gas in the utilities market of the east coast, for example, for the first 6 months of 1969 was 45 percent more than in 1968 and residual fuel oil was up 28 percent, while use of coal did not increase at all.

Low sulfur coal: Before addressing the availability of low sulfur coal, it should be noted that in some powerplants this kind of coal cannot be burned in existing furnaces without operational difficulties or incurring high capital costs for furnace modifications.

Sulfur, unfortunately, is universally present in coal not in elemental form but combined with the organic coal substances or in the form of

[1] Electrical World, Nov. 10, 1969, p. 25.

pyrite. In most U.S. coals, the total sulfur content varies from 0.5 to 6 percent. Much of the coal now burned by powerplants is high sulfur coal, that is, with a content of 1 percent or more.

In terms of national coal reserves of all classes, approximately 50 percent are located east of the Mississippi River and 50 percent on the western side. However, of the total reserves of low sulfur coal with less than 1 percent sulfur, almost 90 percent, including lignite, is located west of the Mississippi. The Office of Science and Technology asserts that the supply of low sulfur coal is costly and limited. The National Coal Policy Conference asserts the supply for power generation is wholly inadequate and is in extremely short supply.

Most of the low-sulfur coal in the East is of metallurgical grade coking quality and is largely dedicated to the steel industries, both domestic and foreign. These fine grade coals are produced in West Virginia and adjoining States and are in demand throughout the free world. They constitute a large source of export tonnage and income which makes an important contribution to the national balance of payments.

Even with a premium of $2 to $3 per ton, which would be required in the East, producers of low sulfur coal may not be able to supply the rapidly growing demand for this commodity. Even if supplies were available, the premium price would result in substantially higher costs of generation.

According to the Department of the Interior, about two-thirds of the coal produced east of the Mississippi River cannot meet present limits for sulfur content and virtually none of it will be able to meet the more restrictive standard of 0.37 percent that some States have scheduled by the end of the year 1971.

Low sulfur oil: Some residual oils from abroad are low enough in sulfur content to be used in steam electric powerplants. A decision announced by the Secretary of the Interior in July 1967, revised Government oil import controls to combat air pollution. The change allowed fuel users a greater supply of low-sulfur fuel oil by reclassifying No. 4 and other low-sulfur oil, previously subject to import quotas, to the category of "residual" fuel oil. This reclassification permitted the east coast to import low-sulfur oil with few import restrictions. And the Interior Department established a system to permit imports of low-sulfur fuel on the west coast and allowed U.S. refiners a special allocation for low-sulfur fuel they manufacture from imported oil.

The inporting of residual fuel oil has recently become a matter of controversy before Congress, for the utilities are seeking to import larger quantities. For example, recently the Commonwealth Edison Co. asked for a special quota to import 6 million barrels of residual from Venezuela into the interior of the Nation via the Mississippi River. The company chose to do this, paying an estimated additional $5 million per year rather than attempt to remove sulfur dioxide from the furnace gases. The cost of heat energy from this imported residual is estimated at 44 to 52 cents per million B.t.u. in comparison with coal at 24 cents per million B.t.u.

Gas: Natural gas already appears to be in short supply and pipeline and distributing companies are experiencing difficulties, according to the National Coal Policy Conference, in meeting increased consumption of present customers. Some technical prospects exist for

producing gas from coal. The Bureau of Mines and the Department of the Interior are sponsoring pilot plant studies on gasification. According to the Bureau, if a decision were made to press ahead, a commercial coal gasification plant could be operating by 1977. However whether the demonstration and subsequent adoption of gasification technology could be carried out fast enough to help substantially with the anticipated gas shortage seems doubtful.

Removal of sulfur from fuels.—At present it seems unlikely that commercial processes to remove sulfur from coal will be available during the next few years, when many critical decisions will have to be made about fuel for large new powerplants. According to the Office of Science and Technology, research projects do show promise of removing as much as 70 percent of the sulfur, although the final product might still contain enough sulfur to be classified as a high sulfur fuel. What the technological and economic feasibility of such removal processes may be remains to be seen.

The sulfur content of fuel oil, on the other hand, can be brought within acceptable amounts either by removing some of the sulfur, or by diluting a high sulfur oil with low sulfur oil, or both.

Present technology indicates that the most economical means of removing sulfur from residual oil for use in electric powerplants may be at the refinery. The OST estimates that oil can be desulfurized for a cost of about 25 to 50 cents a barrel depending upon the original material, the amount of sulfur to be removed and processing methods. The capital investment to build a desulfurizing plant is estimated at about $260 per barrel of daily capacity.

The petroleum industry is investing heavily in ways to reduce sulfur content of fuel oil. Esso, for example, is installing such a plant in Venezuela to produce 100,000 barrels a day primarily for east coast powerplants. Prof. Thomas K. Sherwood of Massachusetts Institute of Technology estimates that the refining to reduce sulfur content from 2.6 to 0.5 percent will increase the price of residual fuel oil to the power station by 50 to 80 cents per barrel, an increase of 20 to 35 percent. For comparison, an increase of 50 cents per barrel would be expected to increase the cost of generation by about 0.7 mills per kilowatt-hour in a modern steamplant.[1]

While domestic crude oil is generally lower in sulfur than the imported oils, it is priced too high for fuel use in generating electricity. Only about one-third of the residual oil marketed in the United States is derived from domestic sources.

Removal of sulfur during combustion.—Five technical processes are in various stages of research, development, and demonstration for removal of sulfur dioxide from the furnace gases of a steam-electric powerplant. The remaining technological problems for this alternative appear much closer to solution than for reducing the sulfur content of coal. However, the search for an economic method of removing sulfur compounds from the gases has been going on for 30 years with no commercially available devices yet available for modern powerplants. The coal industry in particular would encourage Federal support of research into sulfur compound removal so as to insure the future use for coal in generating electricity.

[1] Thomas K. Sherwood, "Must We Breathe Sulfur Oxides?" Technology Review, January 1970, p. 27.

The Office of Science and Technology identifies the three post-combustion removal processes which show the most promise of eventual commercial success as the alkalized alumina process, the catalytic oxidation process, and the limestone/dolomite processes. Each is relatively expensive. The first requires large and complex equipment so that its application is limited to new, large powerplants. The third is less expensive, requires less equipment, and can be adapted to existing powerplants. All are in various stages of development.

It seems evident that regardless of the system chosen for removal of various offensive gases, additional space will be needed at a powerplant to erect the equipment and to provide storage for the extracted wastes. For instance, the waste produced by the limestone/dolomite process for a 1,250 megawatt powerplant is about 2,000 tons per day.

The Consolidated Coal Co. in February 1970 announced that it had developed a process for removing sulfur oxide from stack gas. According to the company, this process, which differs from others being developed, can be used in existing or new powerplants. It would produce elemental sulfur as a product, which can easily be stored, and should find a ready market. Whether it will be used remains to be seen.

In January 1970, an experimental installation of the limestone/dolomite process began an 18-month test at TVA's Shawnee steamplant near Paducah, Ky.

As for costs, these remain conjectural. One estimate for the limestone/dolomite process puts the initial capital cost at $10 per kilowatt. Figuring in operating and fixed charges, the costs come to the equivalent of 25 cents per barrel of oil burned for 1 percent sulfur oil and 30 cents per barrel for 3 percent fuel. If the price of 1 percent oil is $2 per barrel, this system would increase the equivalent fuel cost by 12½ percent, and the cost of generation by 0.4 mill per kilowatt-hour.

The National Coal Association estimates that the first generation of sulfur dioxide removal plants will operate at a cost range of 75 cents to $1 per ton of coal burned and that, as the technology improves, future costs should drop to about 20 to 25 cents per ton of coal burned.

Improving the combustion of coal.—Another strategy is to reduce sulfur emissions from coal-fired powerplants by radically changing the method of burning coal. Instead of burning pulverized coal, a so-called fluidized bed technique could be used. The Office of Coal Research is optimistic on this approach because it believes it can reduce air pollution, lower capital and operating costs of coal-fired plants. However, because of tight funds, the Office of Coal Research has terminated its support for this development. The Nationl Air Pollution Control Administration has indicated it believes the air pollution aspect of the fluidized bed process warrants further investigation and plans to provide some support. However, unless the development and demonstration of this technique is expedited, the chances that it can be used in large new powerplants ordered during the 1970's are slim.

Dispersing and diluting sulfur emissions in the air.—Since the effects of sulfur dioxide depend upon its concentration in the air, one way to reduce its effects is to dilute the emission from a large powerplant by discharging the furnace gases from very tall stacks. Such stacks may be effective in reducing the ground-level concentration of pollutants, but they do not reduce the amount of pollutants released into the air. Also, under some local weather they may not cause dispersion and high concentrations of sulfur dioxide may occur at the ground.

The 1,200 foot stack of a power plant in West Virginia is the highest power plant stack to date. The cost of tall stacks is considered to be about 10 to 20 percent of the estimated cost of some of the sulfur removal processes discussed above. The OST thinks it doubtful that the stacks will be able to afford the dilution necessary to meet stringent sulfur dioxide standards particularly for a large plant that burns high sulfur fuel.

Nitrogen oxides

The nitrogen compounds contained in fossil fuels are released to the air during combustion, usually in the form of oxides of nitrogen.

Among the fossil fuels, pulverized coal is the greatest producer of nitrogen oxides, with oil next and gas last. The Federal Power Commission estimates that the following amounts of nitrogen oxides can be expected from the combustion of coal, oil, and gas in generating 1000 kilowatt-hours of electric power: Coal, 8.6 pounds; oil, 7.6 pounds; and gas, 4.1 pounds.

Effects of nitrogen oxides

Until the 1950's, when these chemicals were implicated in the formation of eye-irritating smog in the Los Angeles area, nitrogen oxides were ignored as a pollutant from steam electric powerplants. Since then some research has been done on the formation of these oxides and general methods of reducing emission of nitrogen oxides have been suggested. However in comparison to the effort to control emission of sulfur oxides, the research on nitrogen oxides is practically nonexistant.

Since nitrogen oxides are produced by stationary and vehicular combustion sources, both of these sources contribute to smog. The exact role of each has not been clearly defined.

Regulation of nitrogen oxides

At present regulation of nitrogen oxide as a gaseous pollutant from powerplants has received only secondary attention. The National Air Pollution Control Administration will not issue criteria for their emissions until 1971.

Actual regulation now is carried out by State and local air pollution control agencies, as with sulfur oxides.

Control systems

No tested systems to control the emission of nitrogen oxides are commercially available for powerplants. In comparison to the massive effort now underway to control the oxides of sulfur, research on nitrogen oxide control is practically nonexistent.

Use of alternative fuels is not a real option because, as seen above, the combustion of fossil fuels all yield roughly comparable quantities.

Cost of control

At present any cost estimate for control of nitrogen oxide emissions would be purely speculative.

Solid wastes from powerplants

Fly ash and furnace ash are wastes from combustion of oil and coal in powerplants. Emissions are dependent upon fuel quality, type of equipment, size and method of firing, and maintenance and operation. Ash emission from burning of natural gas is insignificant in comparison with other fossil fuels.

Effects of fly ash

The principal environmental effect of fly ash which is discharged to the air is the dirt it deposits on surrounding homes and factories.

The 297 million tons of coal burned for electric power in 1968 produced approximately 29.6 million tons of this waste material. Until about 10 years ago, nearly all of this was stored in piles near the utility plant, resulting in destruction of the vegetation near the plant, creating an adverse esthetic effect, contributing to air pollution as the dried ash blew about, and damaging streams, crops and vegetation by the leaching of chemicals from the ash piles by rain water. It is estimated that 200 million tons have been stored on the surface in the past 10 years. If the storage piles averaged 40 feet in height, approximately 2000 acres would be covered with this material. One estimate of the ash to be generated by coal combustion from 1968 to the year 2000 is for 1.9 billion tons, which would occupy 20,000 acres if not otherwise disposed of.

Regulation of particulate emission

Regulation of the amount and characteristics of particulate emissions permitted from powerplants and other users of fossil fuels is the function of local air pollution control agencies.

Control of particulate emissions

Control of emissions from powerplants has, in the past, emphasized "smoke" and particulate control. Four fundamental types of control equipment have been developed: mechanical separators, electrostatic precipitators, bag houses, and scrubbers. There latter two are found most frequently in conventional manufacturing industries and are often included to recover otherwise valuable lost materials.

The technology to collect fly ash has shown a continuing improvement. The average efficiency of collectors being specified for modern powerplants ranges from 98 to 99 percent. The Office of Science and Technology expects this trend will continue.

Research in electrostatic precipitation is now focused mainly in the collection efficiency region above 99 percent. Despite an anticipated decrease in particulate emissions, some increases are anticipated in the emissions of very small particles. OST notes that these very small particulates may be found to be of particular significance in regard to health effects and possible long-term effects upon the climate.

The disposal of fly ash, as indicated above, presents some problems, particularly if the solid wastes from certain air cleaning processes are added. One approach to disposal of fly ash has been research to convert it into a useful byproduct. At a recent conference on fly ash disposal[1] it was forecast that in 1975 the electric utilities of the United States will be producing fly ash at a rate of approximately 29 million tons per year, together with approximately 13.5 million tons of ash and slag from the furnaces for a total ash production of 42.5 million tons. To dispose of this waste commercially will require improved technologies of use and marketing techniques.

Radioactive wastes from nuclear power

The fissioning of uranium or plutonium atoms in a nuclear power reactor produces large quantities of intensely radioactive materials. In fact, the weight of the radioactive waste products virtually equals

[1] "New Uses For Fly, Other Ash Told to 300 at Pittsburgh," Electrical World, Mar. 30, 1970, pp. 22-23.

the weight of the nuclear fuel atoms that fission. In addition, structural and other materials within a power reactor may become radioactive because of exposure to the neutrons emitted during fission.

Most of these wastes are enclosed within the fuel elements within the reactor, although some of them may escape from the fuel elements through small imperfections in their cladding. These escaped wastes remain within the reactor, which is a closed system.

For routine operations, radioactive wastes from a nuclear powerplant reach the environment in one of two ways. Radioactive gases are collected and routinely vented to the outside air, usually from a tall stack or from a blower atop the powerplant. These gases include radioactive krypton and xenon. Some vapors of iodine may also appear depending upon the amount of leakage from the fuel. Other radioactive wastes are routinely collected during powerplant operations. A small part of these may remain in plant waste waters after these have been filtered and in other ways treated to remove the greatest part of them. The waste water is mixed in with cooling water leaving the plant.

Effects of radioactive wastes

Radiation from radioactive wastes depending upon the amount and nature of the waste and the conditions of exposure to it, may produce noticeable biological effects. Large exposures to such radiation from wastes in the environment or that find their way into an organism, can cause injury or death. The exposures that produce these effects are well known and the nature of the effects are established. This kind of exposure is unlikely to result from the routine operation of a nuclear powerplant, except for an accident which might rupture the reactor and disperse its radioactive contents to the surroundings. The exposure which has prompted most recent concern is prolonged exposure to very small quantities of radioactive wastes which produce radiation less than much of the radiation which exists in nature from naturally radioactive minerals.

Although the radioactive wastes routinely discharged from a nuclear powerplant are within limits specified by the Atomic Energy Commission, some scientists have expressed concern that these small amounts if continuously emitted for long periods of time may find their way into the food chains and water supply. Some waterplants and animals tend selectively to remove and concentrate certain radioactive wastes. For example, radioactive species of cobalt, cesium, and manganese are concentrated in the edible tissues of shellfish, while in dairy country radioactive iodine vapors that condense on grass may appear in the milk of the cows that eat the grass.

The aspect of radiation which arouses the most concern and controversy is its postulated effects upon the genetic mechanism. It is well known that large exposures to radiation can cause mutations in animals such as fruit flies. What is not as well known is the effect of small amounts of radiation upon the inherited characteristics of human beings and other living things. The Federal Radiation Council in its first report had this to say about the genetic effects of radiation:

Although ionizing radiation can induce genetic and somatic effects (effects on the individual during his lifetime other than genetic effects), the evidence at the present time is insufficient to justify

precise conclusions on the nature of the dose-effect relationship especially at low doses and dose rates. Moreover, the evidence is insufficient to prove either the hypothesis of a "damage threshold" (a point below which no damage occurs) or the hypothesis of "no threshold" in man at low doses.[1] Because of limitations of knowledge and the complexities of assessing the effects or radiation exposure, the FRC endorses the philosophy that all exposures should be kept as far below any arbitrarily selected levels as practicable. "There should not be any man-made radiation exposure without the expectation of benefits resulting from such exposure." [2]

Regulation of radioactive wastes

Until recently it was commonly assumed that Congress in the Atomic Energy Acts of 1946 and 1954 had preempted to the Atomic Energy Commission the authority to regulate emission of radioactive wastes from nuclear powerplants. The AEC's regulatory system takes a twofold approach. First, the nuclear powerplants each must obtain first a construction permit to build the plant and then an operating permit to put it into operation. The AEC review of the plant design and construction prior to issuing such permits looks into measures to control the discharge of radioactive wastes. Second, the AEC's regulations in part 20 to title 10 of the Code of Federal Regulations establishes specific limits for the emission of radioactive materials from nuclear powerplants. These latter regulations, however, do not extend to control of natural materials or those that are made artificially radioactive with machines other than nuclear reactors. Control of these substances remains with the States. The AEC on March 28, 1970 announced a proposed amendment to 10 CFR 20 which would require licensees of power reactors to make "* * * every reasonable effort to maintain radiation exposures and releases of radioactive materials in effluents to unrestricted areas as far below the limits specified * * * as practicable." Recently the Minnesota Pollution Control Agency in issuing a permit for the operation of a large nuclear powerplant, included a limitation upon discharge of radioactive wastes which is more restrictive than those of the AEC. The issue of whether this State agency can apply stricter controls than those of the AEC was still in Federal court for decision in April 1970.

The AEC regulations on emission of radioactive wastes are interpretations of guides laid down by the Federal Radiation Council. These guides, in turn, are largely derived from the judgement of scientists who are members of the semiofficial National Council on Radiation Protection and Measurements [which has a Federal charter but receives no Federal funds] and the unofficial but prestigious International Committee on Radiation Protection.

The scientific validity of present AEC regulations in 10 CFR 20 recently has been challenged before the Joint Committee on Atomic Energy and the Subcommittee on Air and Water Pollution of the Senate Committee on Public Works. The Secretary of Health, Education and Welfare also reportedly has called for a general review of the basis for the radiation standards.

[1] "Background Material For the Development of Radiation Protection Standards," Staff Report No. 1 of the Federal Radiation Council, May 13, 1960, p. 36.
[2] Ibid., p. 37.

The principal recent challenge has come from two scientists of the AEC's Lawrence Radiation Laboratory. Drs. John W. Gofman and Arthur R. Tamplin state that in their opinion the most crucial problem facing everyone concerned with atomic energy is to "* * * secure the earliest possible revision downward, by at least a factor of tenfold, of the allowable radiation dosage to the population from peaceful atomic energy activities." [1]

Consequences of a major nuclear accident

While the AEC asserts that the likelihood that a major accident with a nuclear reactor might release much of its contained radioactive wastes is very small, it did in 1957 publish a report on the theoretical possibilities and consequences of such an accident. The purpose of quoting the following excerpts is not to suggest that such an accident is probable, but to indicate what might be the range of results should the improbable accident occur.

According to this AEC report, and depending upon the type of accident and the amount of the radioactive wastes released, the effects might be as follows:

> * * * the theoretical estimates indicate that personal damage might range from a lower limit of none injured or killed to an upper limit, in the worst case, of about 3,400 killed and about 45,000 injured.
>
> Theoretical property damages ranged from a lower limit of about one-half million dollars to an upper limit in the worst case of about $7 billion. This latter figure is largely due to assumed contamination of land with fission products.
>
> Under adverse combinations of conditions considered, it was estimated that people could be killed at distances up to 15 miles and injured at distances of about 45 miles. Land contamination could extend for greater distances.
>
> In the large majority of theoretical reactor accidents considered, the total assumed losses would not exceed a few hundred million dollars.

The AEC has since declined to revise or update this study.

Disposal of high level radioactive wastes

The most likely places for large amounts of radioactive materials to escape to the environment during the routine generation of nuclear power appears to be not at a powerplant, but in the transportation of used fuel from a powerplant to a fuel reprocessing plant, during subsequent reprocessing, there, and in the long term disposal of the radioactive wastes.

After nuclear fuel has been in a power reactor for perhaps a year or more, or if it becomes too damaged for safe use, it is removed. After interim storage at the powerplant, to permit some of its radioactivity to diminish, the used fuel is carried by truck or rail in special containers to a fuel reprocessing plant. There the still usable uranium or plutonium is recovered from the used fuel for subsequent reuse in new fuel.

At present there is one operating commercial nuclear fuel reprocessing plant in the United States, near Buffalo, N.Y. Another is nearing completion near Chicago, Ill., and a third is supposed to start construction in South Carolina during 1970.

At the reprocessing plant, the used nuclear fuel is chopped up and dissolved. The radioactive gases released from the fuel generally would be emitted to the air in concentrations permissible under AEC regulations. Most of the intensely radioactive fission products remain in

[1] Testimony of Drs. Gofman and Tamplin before the Subcommittee on Air and Water Pollution, Senate Committee on Public Works, Nov. 18, 1969.

the waste liquors of the process. The weight of these radioactive wastes is virtually equal to the weight of the uranium that fissioned while the fuel was in the reactor. It is during the reprocessing that the intensely radioactive wastes are in forms which could most easily reach the environment in an accident.

What to do with the wastes is somewhat of an open question. The AEC expects they will be put into solid form and stored in worked-out salt mines. At the moment there is no commercial service for high level radioactive waste disposal. The word "disposal" itself is not accurate, for these wastes cannot be released to the environment. Thus they must be stored indefinitely.

In May 1966, a committee of the National Academy of Sciences in advising the Atomic Energy Commission on geologic aspects of radioactive waste disposal, reiterated the basic rule that "* * * concentrations of radionuclides in waste materials should not be allowed to appear in the earth's biosphere before they have decayed to innocuous levels." [1] This concept requires assurance that during any storage or disposal operations, hazardous amounts of radioactive wastes are isolated from the environment, and that upon completion of the reprocessing, the wastes will remain isolated as long as they might constitute a hazard. For some species of radioactive wastes, this means isolation for periods of six to ten centuries, periods so long, notes the committee, that neither perpetual care nor permanence of records can be relied upon. The committee did not object to radioactive materials reaching the environment in concentrations less than those specified in AEC regulations. Within those limits the committee said it had no concern. Rather it was the possibility of cumulative buildups of long-lived radioactive wastes that may exceed these limits after continued use of doubtful practices and the prospect of unforeseen concentrations in excessive amounts resulting from unexpected and uncontrollable alterations in the future environment that the committee wished to guard against. As for the economics of long term waste disposal, the committee observed that while these are of concern, "* * * they are relegated to second-rank consideration, safety being the matter of first concern always." [2]

The Atomic Energy Commission estimates that over the past 10 years, improvements in chemical processing have reduced the waste volumes from about 1,500 gallons per ton of used uranium processed to about 100 gallons per ton. Assuming an installed nuclear generating capacity of 123,000 megawatts by the year 1980, the AEC estimates the accumulated high level wastes in solution from nuclear power would be 3.5 million gallons, which could be reduced to solids with a volume of about 35,000 cubic feet, the equivalent of a cube of 32 feet to a side. Looking ahead to an installed nuclear capacity of 675,000 megawatts by the end of the century, the accumulated high level liquid wastes, if not previously solidified, would total 55 million gallons, and with a solid volume of 550,000 cubic feet. The AEC categorically states that disposal of high level wastes will pose no significant problem technically or economically.[3]

[1] "Report to the Division of Reactor Development and Technology, U.S. Atomic Energy Commission," National Academy of Sciences-National Research Council, Division of Earth Sciences, Committee on Geologic Aspects of Radioactive Waste Disposal. May 1966, p. 18.

[2] Ibid., p. 19.

[3] Testimony of Milton Shaw as excerpted in "Selected materials on environmental effects of producing electric power." Joint Committee on Atomic Energy, 91st Cong., 1st sess., 1969, p. 45.

The ultimate risk to the environment from reprocessing of nuclear fuels and storage of their wastes in the long run seems likely to depend upon how well the reprocessors comply with AEC regulations. The commercial fuel reprocessor, as is any other service industry, will be under financial pressure to reduce costs which might lead to an attitude of bare compliance, or even neglect of AEC regulations rather than a determined attitude to reduce emissions of radioactive wastes to the lowest level permitted by the fuel reprocessing technology.

Another open item is the question who will own and operate the salt mines or other places for the long term storage of the radioactive wastes.

ENVIRONMENTAL ASPECTS OF TRANSMITTING ELECTRICITY AND THEIR ECONOMIC ASPECTS

The trend toward very large steam-electric powerplants, the growing public insistence upon reliable supply of electricity, and a trend toward citing large powerplants outside of urban areas all combine to increase the demand for more transmission lines. Yet the scarcity of land in the areas of high population, which also are the large users of electricity, and increasing public resistance to transmission lines because of their environmental effects, are two factors that are likely to reduce the ability of the electricity industry to deliver electricity when and where needed during the coming decades.

Primary functions of a transmission system

The primary function of a transmission system is, of course, to carry electricity from generating stations to the areas where it is distributed to local customers. In addition, from the standpoint of bulk power supply—which is becoming more important because of the trend toward large plants—there are three more objectives for adequate transmission capacity. These are to—

(1) Provide additional support for any load areas as may be required in emergencies. The network must be able to handle the automatic flow of power within the system and through its associated interconnections.

(2) Transfer, without serious restrictions, capacity and energy within regions and when available between regions to meet power shortages.

(3) Exchange power and energy on a regional and interregional scale, and to achieve economies in capital and operating costs.

Some effects of transmission systems

In the early days of electric power systems, generating plants were located next to their customers and there was little long-distance movement of any large amounts of electricity. Then as distant customers began to use electricity and as transmission from remote hydroelectric plants became a reality, a trend set in toward higher voltage transmission systems.[1] As the practical transmission distances increased, it became feasible to consider placing new generating plants at places relatively remote from the load centers, which opened up an entirely new outlook upon the siting of powerplants. This was particularly true for the hydroelectric plants and there followed an

[1] As a general rule, doubling the voltage of a transmission system quadruples the electrical energy it can carry.

era of dam building and hydroelectric development. Later, the idea of placing a steam-electric powerplant at the mouth of a coal mine was made feasible by improvements in transmission technology.

The same increases in electric power transmission capability and reduction of unit costs for carrying electricity made it feasible to move large amounts of power between neighboring power systems under exchange or interchange arrangements. The recent trend toward joint-owned generating plants to permit use of larger installations than could be afforded or used by one system alone has been made possible by improved transmission. At the same time, however, joint ownership places greater emphasis on the transmission line costs and right-of-way problems which can be controlling in the selection of a site for such an installation.

The independence of nuclear powerplants from location of primary energy sources suggests the possibility of selecting sites in the vicinity of load centers which may somewhat reduce requirements for transmission. However, strong interconnections would still be needed to assure adequate reliability of interconnected systems.

Technological trends in transmission lines

From the introduction of 110 kilovolt alternating current transmission in the United States in 1908 to about 1950, there was a steady increase in the voltage of transmission lines. See table 49. Then during the 1950's the development of still higher voltage (in excess of 200 kilowatts), or extra-high voltage (EHV) transmission began. The first signification application of direct current EHV in the United States was expected to go into service late in 1969. It is an 800-mile line at 400 kilovolts between the Pacific Northwest and the Pacific Southwest which will be capable of transmitting about 1,330 megawatts.

TABLE 49.—MAXIMUM TRANSMISSION VOLTAGES IN THE UNITED STATES

Year	Kilovolts
1886	3
1892	10
1901	60
1908	110
1923	220
1934	287
1954	345
1964	500

Source: National Power Survey, pt. 1, p. 14.

Forecasts for transmission lines

The FPC report of 1967

In its 1967 report on the prevention of power failures, the Federal Power Commission projected a possible pattern of needed power transmission capability for 1975 and estimated the approximate cost.

About half of the added lines were already programed or then under consideration by utilities or pools for completion in the later 1960's or early 1970's. A major part were in the east-central, north-central, and far west regions of the United States. Additions in EHV lines beyond those scheduled for service in 1967 included 16,000 miles of 345 kilovolt line, 21,400 miles of 500 kilovolt line, 5,750 miles of 765 kilovolt lines and 1,665 miles of 400 kilovolt direct current transmission.

As for the comparative capacity of these lines for carriage of electricity, if 230 kilovolt transmission is taken as unity, a 345 kilovolt line can carry 2.75 times as much electricity; a 500 kilovolt line 6 times as much, and a 765 kilovolt line 16 times as much.

As estimate of the approximate cost of the transmission system additions from 1967 through 1975 was $8 billion.

The current forecast

The Federal Power Commission last year reported the projected general plans for transmission of its six regional advisory committees as shown in table 50. The FPC staff, which is independently examining projected requirements, considers these estimates as an appropriate guide for the general size of transmission needs.

Environmental effects of transmission lines

The most obvious environmental effect of electric transmission is the sight of the towers and their cables, and the accompanying withdrawal of land from other use. Lesser effects include interference with reception of radio and television signals under certain conditions and, in the case of direct current lines, the possibility of corrosion of underground metallic structures, such as sewer or water pipes, because of electrical currents within the earth.

The 300,000 miles of electric power transmission lines in service today occupy about 4 million acres of land, or the equivalent of more than 10,000 average sized farms. By 1990 the forecast 497,000 miles of transmission lines will require roughly 7,100,000 acres, or more than 11,000 square miles. In comparison, the area of the State of Connecticut is 5,000 square miles. The rights-of-way widths will probably average more than 142 feet for a single circuit line. The higher voltage transmission lines will require widths of 200 feet or more, and multiple line rights-of-way will be still wider.

TABLE 50.—PROJECTED TOTAL INSTALLATION OF MAJOR TRANSMISSION LINES IN CIRCUIT MILES

Voltage class (kilovolts)	1970	1980	1990
69 to 200	235,000	290,000	335,000
230	40,500	59,300	67,000
345	16,600	34,500	50,500
500	7,500	21,300	34,700
765	560	3,500	10,200
Total	300,160	408,600	497,400

Source: "Environmental effects of producing electric power." op. cit., p. 58.

The greater use of EHV transmission will minimize the total number of miles of overhead transmission, but the wider rights-of-way, the more massive and higher towers, and the larger conductors could, in view of the FPC, compound the problems in seeking to preserve environmental values.[1]

Through the 1990's it is expected that overhead transmission will dominate, for the technology for high voltage underground transmission is not expected to be available. A large, 2,400 megawatt powerplant typically would be the juncture of three rights-of-way, each 200 feet wide.

[1] Ibid., p. 59.

It is apparent, according to the FPC, that the more densely populated regions are generally expected to have the greatest increase in transmission requirements. Thus it should be anticipated that utilities serving these population centers will encounter increasing difficulties in acquiring new rights-of-way in these areas.[1]

Regulation of transmission lines

Governmental review of proposed transmission line construction is limited for both the Federal and State levels of government. FPC regulatory authority is largely limited to lines associated with Government licensed hydroelectric plants, or land of such projects crossed by transmission lines. As for the States, with few exceptions, State regulatory commissions are vested with little or no authority over the location of transmission lines. Less than a dozen States report they have significant jurisdiction over new transmission lines. The remainder either have no jurisdiction, or have jurisdiction in special cases only. Of the 51 State regulatory commissions, 25 have no jurisdiction of any kind over the routing of transmission lines. Of the 51 regulatory commissions, 16 indicated that esthetics and environmental matters were, or could be, among the factors taken into consideration. Others indicated their review was limited by law to matters such as safety, property of investment, and necessity for the line. In many States, transmission line construction is regulated piecemeal by local agencies.[2]

Corrective measures

Two different approaches to mitigating the effects of transmission lines are visible. One is to put the lines underground. The other is to encourage multiple use of the land required for their rights of way.

Underground transmission of electricity

Ideally there should be more underground transmission in urban areas, in locations of exceptional beauty, along scenic highways and rivers and through historic sites. However despite the mounting public desire for more underground transmission, the technology to do so is developing slowly. Even if EHV underground transmission technology is developed, it seems likely that the anticipated high costs for its use in the foreseeable future will preclude any significant shift from overhead transmission.

Multiple land use

One way to reduce the impacts of rights-of-way is to permit multiple use. For example, electricity, gas, oil, and rail traffic might move in the same corridors. Or, the rights-of-way might be used for recreation, or agriculture. However, as Vice Chairman Carl E. Bagge of the Federal Power Commission points out, the historical relations among utilities is one of independence and outright opposition to the idea of joint use. In his opinion, the Nation must evolve transportation and communication and energy corridors as an urgent matter of national policy. Yet there is still no effective communication between the rail, gas,[3] and electric interests to this end.

[1] This theme was explored in more detail by FPC Vice Chairman Carl E. Bagge before the Joint Committee on Atomic Energy in 1969. Cf. "Environmental Effects of Producing Electric Power," op. cit., pp. 449–451.

[2] Testimony of Chairman John N. Nassikas of the Federal Power Commission before the Joint Committee on Atomic Energy. Cf. "Environmental Effects of Producing Electric Power," op. cit., p. 66.

[3] Testimony of Vice Chairman Carl E. Bagge, Federal Power Commission, before the Joint Committee on Atomic Energy. Cf. "Environmental Effects of Producing Power," op. cit., pp. 472–473.

The Electric Power Council on Environment

One response of the electricity industry to the growing problems caused by the adverse effects of some powerplant operations was the formation of an Electric Power Council on Environment. Formed on September 25, 1969, the council's membership includes representatives of the privately, publicly and cooperatively owned power systems and the Federal operations of the Department of the Interior and the Tennessee Valley Authority. The council's objectives are:

Coordination of industry environmental programs;

Encouragement of cooperation between Government and industry; and

Stimulation of environmental research.

Four committees of the council will cover air pollution, water pollution, land use and esthetics. The representatives of the privately owned utilities are also members of the Edison Electric Institute's Committee on the Environment.

Appendix I

Electric Power, Fuels Development, and Protection of the Environment: Legislation Introduced in the 91st Congress

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Introduction

Significant issues that have influenced national energy policy over the past decade include: (i) a steadily rising public demand for more power and also a cleaner environment; (ii) the recent incidence and continued expectation of power "blackouts"; (iii) a host of unsettled questions regarding public acceptance of nuclear power development, and; (iv) the growing U.S. dependence on offshore and foreign oil resources. Widespread concern has been expressed over oil spillages from wells and tankers, conflicts between the siting of new powerplants and the preservation of scenic resources, radioactivity risks and thermal pollution problems of nuclear powerplants, and the destruction of land resources from coal mining and processing. The urgency of the task of satisfying both the expanded demand for electric power and considerations of environmental quality is underscored by the exceptionally large volume of energy-related legislation introduced in the 91st Congress.

Selected bills introduced in the 1st and 2d sessions (through April 15, 1970) are listed below under three headings: "Power Production," "Fuels Development," and "Environmental Protection."

POWER PRODUCTION

Bill and sponsor	Subject	Committee
S. 1071, Mr. Kennedy et al.; H.R. 7186, Mr. MacDonald et al.	Amends the Federal Power Act to further promote the reliability, abundance ,economy and efficiency of bulk electric power supplies through regional and interregional coordination. Provides for the establishment of regional councils made up of electric systems in an area to encourage coordination. Provides for the establishment of a National Council on Environment with 5 members appointed by the President. Empowers the Federal Power Commission upon recommendation of a regional council or upon its own motion to promulgate reliability standards for the planning and operation of bulk powers facilities. Authorizes the Commission to order any electric system to establish physical connection of its transmission facilities with the facilities of one or more other electric systems. Directs the Commission to conduct research on high voltage heavy current electricity.	Commerce, Interstate and Foreign Commerce.
H.R. 12585, Mr. MacDonald	Encourages long range planning by regional councils. Directs the Federal Power Commission to recognize existing regional councils or secure the establishment of appropriate regional coordination organizations. Provides for the establishment of standards to guide each electric utility operating bulk power facilities in a region. Requires an electric utility to obtain the prior approval of the Commission before constructing extra-high voltage transmission facilities or thermal plants. Grants to electric utilities who have complied with the provisions of this act in the desire to construct and maintein EHV facilities (1) the power of eminent domain; and (2) rights-of-way on Federal lands.	Interstate and Foreign Commerce.
S. 1916, Mr. Magnuson by request	States that the purpose of this act is to promote the reliability, abundance, and efficiency of bulk power supply in the United States and to assure that actions pursuant to all parts of the Federal Power Act shall have due regard for the enhancement and preservation of the environment, the conservation of natural resources and the strengthening of long-range land use and planning. Encourages the strengthening of existing mechanisms for coordination of electric utility systems. Encourages the installation and use of the products of advancing technology with due regard for the preservation and enhancement of the environment and natural resources.	Commerce.
S. 2752, Mr. Muskie	Specifies procedures for the establishment of regional districts for the purpose of coordinating power development and protecting the environment. Directs the electric utilities within each regional district to propose reliability and adequacy standards. Directs the agency administering this act to review and act on approval of the proposed standards. Authorizes the agency to promulgate and distribute criteria for the development of procedures for the siting and construction of bulk power facilities. Provides that no person shall undertake the construction or modification of any bulk power facility after 6 months after the administering agency has approved standards of procedures for regional districts without notice by the regional board of compliance with the standards and procedures approved for the regions.	Government Operations.
H.R. 2506, Mr. Saylor; related bills: H.R. 15727, H.R. 15955.	Directs the Federal Power Commission to conduct a national study and prepare a comprehensive national study siting plan of the optimum locations for large electric power generating facilities of all types to: (1) insure availability of an abundant, low-cost, and reliable supply of electricity from such facilities, and (2) protect environmental assets of the country. Sets out additional related duties for the Federal Power Commission to perform while carrying out the above duties. Requires the Federal Power Commission to start the study within 90 days after enactment of this act and to submit its national powerplant siting plan to Congress within 2 years after that date. Sets limitations on the Atomic Energy Commission's issuance of licenses for the utilization of nuclear energy for the production of electric power.	Interstate and Foreign Commerce.
S. 607, Mr. Metcalf et al.; H.R. 4866, Mr. Tiernan et al	Establishes as an independent agency in the Executive branch, the U.S. Office of Utility Consumers' Counsel, headed by Counsel appointed by the President for a 5-year term. Authorizes the Counsel to represent the interests of the Federal Government and the consumers of the Nation before Federal and State regulatory agencies with respect to matters pertaining to electric, gas, telephone, and telegraph utilities. Authorizes the Counsel to compile and disseminate to the public information and reports on utilities affecting the consumers' economic interest, to give technical assistance to State and local governments and to make use of model laws.	Government Operations. Interstate and Foreign Commerce.

H.R. 661, Mr. Seylor	Establishes a uniform Federal policy for repayment of capital costs of Federal electric power projects, and authorizes the Secretary of the Interior to carry out this policy. Requires the Federal cost to be repaid within the useful life of such project, and provides that the maximum repayment period shall not extend beyond 50 years.	Interior and Insular Affairs.
H.R. 10255, Mr. Ottinger	Extends the jurisdiction of the Federal Power Commission to cooperatives and municipalities which own or operate generating or transmission facilities used in interstate commerce.	Interstate and Foreign Commerce.
H.R. 5492, Mr. Burleson	Provides that, in fixing rates for the transportation of natural gas in interstate commerce of for the sale in interstate commerce of natural gas for resale, the Federal Power Commission shall reflect changes in purchasing power of the dollar after Dec. 31, 1968, in determining the utility plant and related reserve components of rate base for natural-gas pipeline companies.	Do.
H.R. 14531, H.R. 16124, Mr. Bingham	Transfers such functions which relate to the regulation of commercial uses of nuclear power from the Atomic Energy Commission to the Secretary of HEW to be edministered through the Public Health Service subject (in certain cases) to disapproval by the Federal Power Commissioner or the Secretary of the Interior.	Atomic Energy.
S. 1883, Mr. Pastore by request; H.R. 9647, Mr. Holifield by request.	Requires the Atomic Energy Commission to regard nuclear power plants as profit-making commercial ventures subject to licensing in accordance with the competitive criteria of the antitrust laws.	Do.
S. 1885, Mr. Pastore et. al.; H.R. 477, Mr. Hosmer et. al.; related bill, H.R. 10288.	Authorizes the AEC to enter into contracts necessary or desirable for the provision of services involving the detonation of nuclear explosive devices for peaceful purposes and to establish prices for such service. Restricts such contracts to insure that all nuclear devices used in the performance of such services are kept in the control and custody of the Commission. Requires that all such contracts: (1) protect health; (2) minimize the danger to life or property; and (3) require the reporting and permit the inspection of work performed.	Do.
S. 1628, Messrs. Jackson and Church	Grants the consent of Congress to the western interstate nuclear compact and related purposed.	Judiciary
H.R. 662, Mr. Saylor; related bill, H.R. 4266	Requires congressional approval before a license may be granted for the construction or operation of any facility for the commercial generation of electricity from nuclear energy.	Atomic Energy.
S.J. Res. 91, Mr. Cook et al.; H.J. Res. 83, Mr. Saylor; H.J. Res. 228, H.J. Res. 255, H.J. Res. 278, and others.	Creates a Federal Committee on Nuclear Development to be appointed by the President by and with the consent of the Senate. Directs the Committee to study, review, and evaluate present provisions of the Atomic Energy Act and intensively probe the atomic energy program of the United States generally, with the specific objectives of ascertaining whether the existing civilian nuclear program is responsive to the public need, assessing the validity of the assumptions upon which the existing program is built and determining what changes should be made in that program. Grants the Committee necessary powers.	Do.

FUELS DEVELOPMENT

S. 719, Mr. Allott	Establishes a national minerals and mining policy to promote the wise and efficient use of mineral resources. Provides that the Secretary of the Interior be responsible for implementing the mining and minerals policy.	Interior.
S. 2005, Amt. No. 153, Mr. Boggs et al	The title of the proposed amendment would be cited as the "National Materials Policy Act of 1969." Establishes a 7-member Commission on materials policy, which would be charged with a full study of a possible national materials policy. The Commission would be appointed by the President with the advice and consent of the Senate. It would report to the President and the Congress with respect to its findings and recommendations no later than June 30, 1971.	Public Works.
H. Res. 810, Mrs. Hansen	Creates a Select Committee of the House of Representatives to be composed of 7 Members to investigate oil and pipeline operations in Alaska. Directs the committee to make a full and complete study of the fiscal and physical operations of various oil companies and levels of governments involved in the exploration, drilling, pumping, transportation, and disposition of petroleum products of Alaska.	Rules.
S. 3112, Mr. Byrd	Requires the Secretary of the Interior, through the Office of Coal Research, to make a complete investigation and study, including research, into possible uses of solid wastes resulting from the mining and processing of coal. Requires a report and recommendations to Congress not later than 1 year after the date of enactment of this act.	Interior and Insular Affairs.

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FUELS DEVELOPMENT—Continued

Bill and sponsor	Subject	Committee
H.R. 9896, Mr. Vanik, related bills: H.R. 9897, H.R. 9975, H.R. 10205, H.R. 10628, H.R. 11782.	Provides that percentage depletion under the Internal Revenue Code shall not be allowed in the case of mines, wells, and other natural deposits located in foreign territory.	Ways and means.
H.R. 2716, Mr. Saylor	Increases the depletion allowance to the present maximum (27½ percent) for all minerals produced in the United States Provides for a depletion allowance ranging from 5 to 27½ percent for all minerals produced outside the United States. (Amends 26 U.S.C. 613.)	Do.
H. Con. Res. 329, Mr. Heckler	Requests the President to make reviews of Government programs, etc. so as to provide increased production and employment in critically depressed domestic mining and minerals industries. Makes it the sense of the Congress that it is in the national interest to foster and encourage: (1) the maintenance and development of a sound and stable domestic mining and minerals industry; (2) the orderly discovery and development of domestic minerals resources and reserves in Federal, State, and privately owned lands; and (3) mining, mineral, metallurgical, and marketing research to promote the wise and efficient uses of domestic metal and mineral resources. Makes it the sense of the Congress that the maintenance and development of a sound and stable domestic mining and minerals industry cannot be accomplished by the maintenance of national stockpiles for planned defense needs in a single emergency or the existence of productivity capacity based upon the importance of foreign materials.	Interior and Insular Affairs.
S. 2848, Mr. Nelson; H.R. 7354, Messrs. Saylor and Dingell.	Amends the Mineral Leasing Act, abrogating the mineral law of 1872 and making all minerals on public lands subject to leasing.	Do.
S. 2641, Mr. Allott; H.R. 1319, Mr. Rarick	Provides that when coal, oil shale, bituminous sand and gilsonite are mined as a source of synthetic oil or gas by crushing, retorting, or other extractive processes, such treatment process shall be considered as mining for purpose of determining gross income from property under the Internal Revenue Code.	Finance, Ways, and Means.
H.R. 16194, Mr Lujan	Provides that 90 percent (currently 37½ percent) of all moneys received from sales, bonuses and rentals of public lands under the Mineral Leasing Act of 1920 shall be paid by the Secretary of the Treasury to the State within the boundaries of which the leased lands or deposits are or were located.	Interior and Insular Affairs
S. J. Res. 54, Mr. Anderson; H. J. Res. 506, Mr. MacDonald (Public Law 91-158).	Grants the consent of Congress to an extension and renewal for 2 years of the interstate compact to conserve oil and gas which was signed in Dallas, Tex., on Feb. 16, 1935.	Do.
S. 368, Mr. Bible et al.; H. R. 2370, Mr. Hosmer; related bills: H. R. 7481, H. R. 9508.	Authorizes the Secretary of the Interior to issue leases for the development of geothermal steam and associated geothermal resources on public lands.	Do.
S. 1830, Mr. Jackson et al.; S. 3041, Mr. Gravel; H. R. 10193, H. R. 13142, H. R. 14212 (Mr. Pollock).	Alaska Native Land Claims Settlement. Includes provisions for indigenous people to receive 2 percent of the revenues received by the Federal Government from mineral leases on public lands. They would receive this amount until the amount reached $500 million. Most of the revenue would come from moneys that the Federal Government would otherwise pay to the State as its share of the income from Federal mineral and oil leases.	Do.
S. 1919, Mr. Magnuson by request; H.R. 12151, Mr. Rooney by request.	Provides that under the Natural Gas Pipeline Safety Act, Federal funds may be given to States which act as agents for the Secretary of Transportation in enforcing Federal safety standards for pipeline facilities or the transportation of gas subject to the jurisdiction of the Federal Power Commission under the Natural Gas Act.	Commerce, Interstate and Foreign Commerce.
S. 3579, Mr. Prouty	Permits home heating fuel oil to be imported into the United States for use by ultimate consumers within the New England States without regard to any quantitative limitations or other import restrictions under the Trade Expansion Act. Directs the Secretary of the Interior to issue licenses for the importation of home heating fuel oil if such persons establish to the satisfaction of the Secretary that home heating fuel oil to be imported by him or for his account under such license will be sold for use by ultimate consumers only within the New England States. Authorizes the Secretary to prescribe terms and conditions for the issuance of such licenses. Provides that the importation of home heating fuel oil shall not affect the allocation of imports and issuance of licenses under Presidential Proclamation No. 3279.	Finance.
H.R. 10799, Mr. Conte; related bills: H.R. 10800, H.R. 10801, 1 013, and others.	Provides for the elimination over a 10-year period of the mandatory oil import control program. Prohibits the imposition of import quotas or other mandatory restrictions on or after Jan. 1, 1980, with respect to the importation of crude oil and its derivatives and products.	Ways and Means.

S. 3477, Mr. Stevens and Mr. Bellmon; related bills: S. 3486, H.R. 16126, H.R. 16146, H.R. 16177, and others.	Subdivides the States into oil production districts. Establishes maximum levels of imports for the various districts.	Finance.
H.R. 6554, Mr. Tunney	Directs the Secretary of the Interior to accelerate all necessary administrative and legal steps to clear title to all oil shale lands. Directs the Secretary to submit to Congress within 6 months after enactment of this act a research and development program for *oil shale lands*. Sets standards and limits for authorized test leasing. Prohibits production leasing until July 1, 1973. Allows the Secretary to make contractual agreements with private entities and to utilize joint efforts with other Government agencies to carry out research and development programs. Allows, after 1973, the exchange of lands by the Government to facilitate production leasing.	Interior and Insular Affairs.
S.J. Res. 184, Mr. Tower	Authorizes the Secretary of the Interior to conduct a study of solar rays with a view to determining the potential of such rays as an alternative source of electrical energy.	Commerce.
S.J. Res. 185, Mr. Tower	Authorizes the Secretary of the Interior to conduct a study of the tides of oceans and other bodies of water with a view to determining the potential of such tides as an alternative source of electrical energy.	Do.

ENVIRONMENTAL PROTECTION

H.R. 15783, Mr. McClure	Extends the life of the Public Land Law Review Commission. Declares it to be the policy of Congress that immediate action should be undertaken toward developing and implementing new programs to control and prevent the pollution and other destruction of our land, waters, atmosphere, and scenic heritage. Directs the Commission to formulate recommendations to protect the environment and to submit a report not later than Dec. 31, 1974.	Interior.
S. 3042, Mr. Gravel et al	Provides for the study and evaluation of the air and water pollution and other environmental effects of underground uses of nuclear energy for excavation and other purposes. Creates a 15-man study Commission composed of leading scientific experts. *Provides* that the Commission report their findings to the President and the Congress within a year. Provides that the Commission shall evaluate the following environmental risks attendant upon the underground use of nuclear energy: (1) the effect on the public health and welfare; (2) the effect on terrestrial, marine, and fresh water ecosystems, including the generation of earthquakes and other seismic activity and other geophysical phenomena; and (3) the transport of radioactivity through the environment. Requires the Commission to evaluate the risks attendant upon the use of nuclear energy to remove or lower natural biological barriers which may cause the introduction of nonindigenous species into ecosystems.	Public Works.
S. 7, Mr. Muskie; H.R. 4148, Mr. Blatnik, Public Law 91–224.	Amends the Federal Water Pollution Control Act, as amended, to control and clean up discharges of oil from vessels and onshore and offshore facilities, and to conduct a demonstration program for the elimination or control of acid or other mine water pollution resulting from active or abandoned mines. Sec. 21, directed primarily to the Atomic Energy Commission and Corps of Engineers, requires that any applicant for a Federal license or permit obtain certification of reasonable assurance of compliance with water quality standards from a State before that applicant can receive any license or permit.	Do.
S. 212, Messrs. Anderson and Aiken; related bills: H. R. 9647, S. 1883, S. 2768.	Amends the Atomic Energy Act of 1954, as amended: (1) to make the Atomic Energy Commission responsible for regulation of discharges of heat from nuclear powerplants to cooling waters; (2) to eliminate the "Finding of Practical Value" of sec. 102 and to substitute requirement that AEC license all nuclear power facilities under sec 103 (commercial) unless the applicant for a license and AEC can demonstrate that the facility's function will be primarily research and development, in which case it can be licensed under sec. 104 (Medical Therapy and Research and Development); and (3) to provide for greater participation of the Justice Department in consideration of licenses for nuclear power-plants.	Atomic Energy.
S. 524, Mr. Jackson; H.R. 659, Mr. Saylor; related bills: H.R. 222, 2505, 12363.	Establishes a State-Federal program for the regulation of surface mining operations. Provides for the preparation of State plans for the reclamation of surface-mined areas and authorizes 50 percent grants to cover the Federal share in the Federal-State program. Authorizes the Secretary of the Interior to make investigations of surface mines, and to conduct an accelerated program of research and experiments.	Interior and Insular Affairs.

ENVIRONMENTAL PROTECTION—Continued

Bill and sponsor	Subject	Committee
S. 3491, Mr. Nelson	Requires the Secretary of the Interior to develop standards and reclamation requirements for previously strip-mined lands as well as for all future surface and strip mining operations. Encourages the States to adopt standards and regulations of their own. Authorizes the Secretary of Agriculture to enter into agreements with State and local governments to provide financial and technical assistance for the reclamation of strip- or surface-mined lands owned by those State and local governments. Authorizes the Secretary of Agriculture to provide technical assistance and cost sharing for the conservation and reclamation of privately owned stipe-mined lands. Authorizes the Secretary of the Interior to acquire certain strip-mined lands for the purpose of their reclamation and in order to establish an effective continuing conservation, land use, and management program.	Do.
H.J. Res. 49, Mr. Long, related bills: H. Res. 163, H.R. 488, H.R. 501.	Directs the Secretary of Housing and Urban Development to make a full and complete study of the means of measuring the extent of the economic and other damage that may result from the erection of overhead electrical transmission towers and lines giving particular consideration to the impact of such towers and lines upon scenic assets, zoning, and community planning, property values, real estate revenues, and other such factors which may be relevant.	Interior and Foreign Commerce.
H.R. 487, Mr. Long; related bill: H.R. 500	Authorizes the Secretary of the Interior to conduct a program of research and development to encourage the use of underground transmission of electrical power and to cooperate with the Department of Interior and other Federal instrumentalities engaged in the transmission of electric power in undertaking projects to evaluate and demonstrate the economical and technical feasibility of such transmission.	Do.
H.R. 1198, Mr. Long	Provides for an amortization deduction and an increased tax credit under the Internal Revenue Code relating to sums spent for transferring electric transmission lines underground.	Ways and Means.
S. 940, Messrs. Jordan and Church	Prohibits the licensing of hydroelectric projects on the Middle Snake River below Hells Canyon Dam for a period of 10 years.	Interior and Insular Affairs.
S. 1075, Mr. Jackson et al., H.R. 12549, Mr. Dingell et al., Public Law 91–190.	Established as national policy that Federal, State, and local governments shall act to protect the environment. Directed all agencies of the Federal Government to include environmental factors in decisionmaking. Sec. 102 states that all agencies of the Federal Government shall include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment a detailed statement by the responsible official on (i) the environmental impact of the proposed action; (ii) any adverse environmental effects which cannot be avoided should the proposal be implemented; (iii) alternatives to the proposed action; (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.	Merchant Marine and Fisheries.
S. 2768, Mr. Tydings	Inserts the phrase "environmental quality" in the Atomic Energy Act of 1954, as amended. Assigns an additional requirement to the licensee of a nuclear facility. Not only must he agree to observe safety standards to protect health and property, he must now agree to observe such standards to protect and promote the preservation of environmental quality as the Commission may by rule establish. Includes an adverse impact on the environment as a reason for denial of a license.	Atomic Energy.
H.R. 421, Messrs. Dingell and Karth	Directs control of water pollution from Federal installations and federally licensed activities by forbidding any Federal department or agency from licensing or permitting any private or public body to engage in any activity which leads to the discharge of heated effluents into navigable waters unless special permission is granted by the Secretary of Health, Education, and Welfare. Directs the Secretary to issue conditions for each license or permit granted by the Federal agency, and establishes necessary procedures to issue the license with a right to a public hearing. Authorizes each department or agency to include in the license conditions to protect fish, wildlife, recreation, and esthetic values.	Public Works.

S. 1592, Messrs. Brooke and Kennedy; related bills: S. 3093 (Mr. Cranston) S. 2393 (Mr. Muskie et al.)	Directs the Secretary of the Interior to study the most feasible and desirable means of establishing certain portions of the tidelands, Outer Continental Shelf, seaward areas, and Great Lakes of the United States as marine sanctuaries, and sets a moratorium on the industrial development of such areas until the study is completed.	Commerce.
S. 1219, Mr. Cranston; related bills: S. 3351 (Messrs. Cranston and Murphy), H.R. 14619 (Mr. Teague), H.R. 3120 (Mr. Teague), and others.	Directs the Secretary of the Interior to make an investigation and study, with respect to drilling and oil production under leases issued pursuant to the Outer Continental Shelf Lands Act. Directs the Secretary to order the cessation of all drilling for oil, gas, or other minerals in the Santa Barbara Channel off the coast of the State of California and to suspend all such drilling off the coast of California until such study and investigation is completed.	Interior and Insular Affairs.
H.R. 857, Mr. Ottinger	Provides protection of fish and wildlife resources under the Fish and Wildlife Coordination Act from the effects of projects licensed by Federal agencies.	Merchant Marine and Fisheries.
H.R. 15753, Mr. Koch; H.R. 16012, Mr. Mikva	Prohibits the introduction, transportation, or distribution in interstate commerce of gasoline containing lead. Requires the Secretary of Health, Education, and Welfare to prescribe regulations for the enforcement of this act. Asserts that any person who willfully violates such provisions or such regulations shall upon conviction be fined not more than $2,000 or imprisoned not more than 6 months, or both.	Interior and Foreign Commerce.
H.R. 15754, Mr. Scheuer	Prohibits the manufacturing and importation of leaded gasoline after Dec. 31, 1975, except under certain conditions. Provides that no motor vehicle manufactured after June 30, 1972, may be sold in or imported into the United States unless it is equipped with a device approved by the Secretary of Health, Education and Welfare for the reduction of pollutants in exhaust emissions.	Ways and Means.
H.R. 16318, Mr. Dingell	Transfers from the AEC to the Secretary of HEW and the Secretary of the Interior all functions, duties, and responsibilities relating to the effect of atomic energy on the health and safety of the public. Provides that those functions, duties, and responsibilities which relate to the control of radiation hazards and thermal pollution resulting from discharge or disposal of radioactive or other effluents (including heated water) into any of the navigable waters of the United States are transferred to and	Atomic Energy.
H.R. 14167, Mr. MacGregor; related bills: H.R. 12512, 14532, 14801.	Allows the imposition by a State under the Atomic Energy Act of more restrictive standards relating to the discharge into the navigable waters of the United States of radioactive materials.	Do.
S.J. Res. 108, Mr. Gravel et. al.; H.J. Res. 99, Mrs. Mink, et al.	Establishes a National Commission on Nuclear and Seismic Safety to be composed of 15 members to be appointed by the President. Directs the Commission to undertake a comprehensive investigation and study of the implications of underground and other nuclear detonations including but not limited to the following: Implications for earthquakes, other seismic disturbances both subterranean and submarine, ecological contamination and waste, and damage to existing structures.	Do.

Appendix II

Published Hearings and Reports of Congressional Committees Relating to Pollution and Environmental Quality, 1965–69

House

Committee on Education and Labor

"Uranium miners compensation." Hearings before the Select Subcommittee on Labor on H. R. 14558 and H. R. 16302. 90th Cong., 1st sess., 1967, 185 p.

"Coal mine health and safety." Hearings before General Subcommittee on Labor on H. R. 4047, H. R. 4295, and H. R. 7976. 91st Cong., 1st. sess., 1969, 2 vols., 658 and 100 p.

Committee on Foreign Affairs

"International implications of dumping poisonous gas and waste into oceans." Hearings before Subcommittee on International Organizations and Movements, 91st Cong., 1st sess., 1969, 151 p.

Committee on Government Operations

"Critical need for a national inventory of industrial wastes. (Water pollution control and abatement)." 30th report by the * * * 90th Cong., 1st sess., 1967, H. Rept. 1579, 34 p.

"Federal air pollution R. & D. on sulfur oxides pollution abatement." Hearings before a Subcommittee of the * * * 90th Cong., 1st sess., 1967, 95 p.

"Effects of population growth on natural resources and the environment." Hearings before Subcommittee, 91st Cong., 1st sess., 1969, 256 p.

"Environmental dangers of open-air testing of lethal chemicals." 10th report by the * * * 91st Cong., 1st sess., 1969, H. Rept. No. 91–633, 62 p.

"Federal air pollution research and development, interim report on sulfur oxides pollution abatement R. & D." 2d report by the * * * 91st Cong., 1st sess., 1969, 21 p.

"1966–68 survey of water pollution control and abatement at Federal installations." 1st report by the * * * 91st Cong., 1st sess., 1969, 159 p.

"Transferring environmental evaluation functions to Environmental Quality Council." Hearing before Subcommittee, 91st Cong., 1st sess., on H.R. 11952, 19656 p.

"Transportation of hazardous materials." Hearing before the Subcommittee on Government Activities, 91st Cong., 1st sess., 1969, 44 p.

Committee on Interstate and Foreign Commerce

"Natural gas pipeline safety." Hearings before the Subcommittee on Communications and Power, on H.R. 6551 and S. 1166, 90th Cong., 1st and 2nd sess., 1967-1968, 244 p.

"Air pollution control research into fuels and motor vehicles." Hearing before the Subcommittee on Public Health and Welfare, 91st Cong., 1st sess., on H. R. 12085, 1969, 125 p.

"Pipeline safety, 1969." Hearing before Subcommittee on Communications and Power, 91st Cong., 1st sess., 1969, 109 p.

"Review of electronic products radiation hazards." Hearings, 91st Cong., 1st sess., 1169, 303 p.

Committee on Merchant Marine and Fisheries

"Council on Environmental Quality." Report to accompany H.R. 12549, 91st Cong., 1st sess., 1969, H. Rept. 378, 2 parts, 37 p.

"Environmental quality." Hearings before Subcommittee on Fisheries and Wildlife Conservation, on H.R. 6750, 91st Cong., 1st sess., 1969, 472 p.

"Oil pollution." Hearings on H.R. 6495, H.R. 6609, H.R. 6794, and H.R. 7325, 91st Cong., 1st sess., 1969, 493 p.

Committee on Public Works

"Water pollution—1967." Hearings, 90th Cong., 1st sess., 1967, 249 p.

"Federal water pollution control act amendments, 1968." Hearings, on H.R. 15906 and related bills. 90th Cong., 2d sess., 1968, 718 p.

"Federal water pollution control act amendments, 1969." Hearing on H.R. 4148 and related bills, 91st Cong., 1st sess., 1969, 677 p.

"Oil spillage, Santa Barbara, California." Hearing before Subcommittee on Flood Control and Subcommittee on Rivers and Harbors, 91st Cong., 1st sess., 1969, 310 p.

"Water quality improvement act of 1969." Report from the * * * to accompany H.R. 4148, 91st Cong., 1st sess., 1969, 60 p. H. Rept. 91-127.

Committee on Science and Astronautics

"The adequacy of technology for pollution abatement." Hearings before the Subcommittee on Science, Research and Development, 89th Cong., 2d sess., 1966, 915 p.

"Adequacy of technology for pollution abatement." Report of Research Management Advisory Panel through Subcommittee on Science, Research, and Development, 89th Cong., 2d sess., 1966, 17 p. Committee print.

"Environmental pollution—a challenge to science and technology." Report of the Subcommittee on Science, Research and Development. 89th Cong., 2d sess., 1966, 60 p. Committee print.

"Environmental quality." Hearings before the Subcommittee on Science, Research and Development on H.R. 7796, 13211 and 14506, 90th Cong., 1st sess., 1967, 588 p.

"Managing the environment." Report of the Subcommittee on Science Research and Development, 90th Cong., 1st sess., 1967, 59 p. Committee print.

House Committee on Science and Astronautics and Senate Committee on Interior and Insular Affairs

"A National policy for the environment." A Congressional White Paper submitted to Congress under the auspices both Committees. 90th Cong., 2d sess., 1968, 19 p.

SENATE

Committee on Commerce

"Overhead and underground transmission lines." Hearings before the Senate Commerce Committee on S. 2507, S. 2508, May 1966. 89th Cong., 2d sess., 1966, 393 p.

"Natural gas pipeline safety regulations." Hearings on S. 1166, 90th Cong., 1st sess., 1967, 426 p.

"Effects of pesticides on sports and commercial fisheries." Hearings before the Subcommittee on Energy, Natural Resources, and the Environment, 91st Cong., 1st sess., 1969, pt. 1, 278 p.

"Gas pipeline safety oversight." Hearings before Subcommittee on Surface Transportation, 91st Cong., 1st sess., 1969, 55 p.

Committees on Commerce and Public Works

"Electric vehicles and other alternatives to internal combustion engine." Joint hearings on S. 451 and S. 453, 90th Cong., 1st sess., 1967, 550 p.

Committee on the District of Columbia

"Problems of air pollution in the District of Columbia." Hearings before the Subcommittee on Business and Commerce and the Subcommittee on Public Health, Education and Welfare, and Safety. 90th Cong., 1st sess., 1967, 909 p.

Committee on Government Operations

"Establish a Select Committee on Technology and the Human Environment." Hearings before the Subcommittee on Intergovernmental Relations on S. Res. 68. 90th Cong., 1st sess., 1967, 409 p.

"Establish A Select Senate Committee on Technology and the Human Environment." Hearings before the Subcommittee on Intergovernmental relations, 91st Cong., 1st sess., on S. Res. 78, 1969, 334 p.

Committee on Interior and Insular Affairs

"Surface mining reclamation." Hearings on S. 3132, S. 3116 and S. 217. 90th Cong., 1st sess., 1967, 28 p.

"Joint Colloquium on a national policy for the environment." Hearing. 90th Cong., 2d sess., 1968, 233 p.

"National environmental policy." Hearing on S. 1075, S. 237, and S. 1752, 91st Cong., 1st sess., 1969, 234 p.

"National environmental policy act of 1969." Report from the * * * to accompany S. 1075, 91st Cong., 1st sess., 1969, 48 p.

Committee on Labor and Public Welfare

"Water pollution, 1969". Hearings before Subcommittee on Air and Water Pollution, on S. 7 and S. 544, 91st Cong., 1st sess., 1969, pt. 4, p. 919–1584.

Committee on Public Works

"Air pollution, 1967 (Air Quality Act.)" Hearings before the Subcommittee on Air and Water Pollution on S. 780. 90th Cong., 1st sess., 1967, Pts. 2–4, pp. 747–2694.

"Water pollution, 1967." Hearings before the Subcommittee on Air and Water Pollution, 90th Cong., 1st sess., 1967, pts. 1, 2; 721 p.

"Air pollution." Hearings before the Subcommittee on Air and Water Pollution, 90th Cong., 2d sess., 1968, 808 p.

"Air quality criteria." Staff report for the Subcommittee on Air and Water Pollution, 90th Cong., 2d sess., 1968, 69 p., Committee print.

"Themal pollution." Hearings before the Subcommittee on Air and Water Pollution. 90th Cong., 2d sess., 1968, 3 pts, 1060 p.

"Waste management research and environmental quality." Hearings before the Subcommittee on Air and Water Pollution 90th Cong., 2d sess., 1968, 451 p.

"Water pollution." Hearings before the Subcommittee on Air and Water Pollution on S. 2525 and S. 3206. 2 pts, 822 p.

"Amending Federal water pollution control act, as amended, and for other purposes." Report of the * * * to accompany S. 7, 91st Cong., 1st sess., 1969, 120 p.

"Clean Air Act amendments of 1969." Report of the * * * to accompany S. 2276, 91st Cong., 1st sess., 1969, 14 p.

'Water pollution, 1969." Hearings before Subcommittee on Air and Water Pollution, on S. 7 and S. 544, 91st Cong., 1st sess., 1969, 3 pts., 918 p.

Joint Committee on Atomic Energy

"Licensing and regulation of nuclear reactors." Hearings, 90th Cong., 1st sess., 1967, 497 p.

"Radiation exposure of uranium miners." Hearings, 90th Cong., 1st sess. 1967, 1373 p.

"Environmental effects of producing electric power." Hearings, 91st Cong. 1st sess., 1969, pt. 1, 1108 p.

"Radiation standards for uranium mining." Hearings before Subcommittee on Research, Development, and Radiation, 91st Cong., 1st sess., 1969, 414 p.

"Selected materials on environmental effects of producing electric power." Joint committee print, 91st Cong., 1 st sess., 1969, 553 p.

Appendix III

Selected Articles on Energy Development

Cheryl Prihoda, Library Services Division, Legislative Reference Service

Battelle Memorial Institute, Columbus, Ohio. Pacific Northwest Laboratories.
A review and comparison of selected United States energy forecasts; prepared for the Executive Office of the President, Office of Science and Technology, Energy Policy Staff. Washington, For sale by the Supt. of Docs., U.S. Govt. Print. Off., 1969 [i.e., 1970] 79 p.

Boydstun, L. B., Allen, G. H., Garcia, F. G.
Reaction of marine fishes around warmwater discharge from an atomic steam-generating plant. Progressive fish-culturist, v. 32, Jan. 1970: 9–16.

Charlier, Roger Henri.
Tidal energy. Sea frontiers, v. 15, Nov.–Dec. 1969: 339–348.
"On November 26, 1966, on the Rance River in Brittany, near the erstwhile pirate town of St. Malo, the cofferdams were removed from the turbines of the first hydroelectric plant to use the energy of the tides. Full operation of the plant began in 1967."

Competing needs of forest and cities tested. Congressional quarterly weekly report, v. 27, Nov. 7, 1969: 2223–2226.
Discusses proposal by New Jersey power companies to make Tocks Island Reservoir and Dam part of a much larger pumped storage project. Conservationists fear that the natural beauty and value of the immediate area, especially Sunfish Pond, will be seriously damaged.

Does Uncle Sam give a dam? Consumer report, v. 35, Mar. 1970: 170–173.
"Congress has a rare chance to end private exploitation of a vast public resource," hydroelectric power.

Energy for the world's technology. New scientist, v. 44, Nov. 13, 1969: 1–24.
"The fuel industries are continually searching for more efficient ways of finding, extracting, and using fuel, and this feature section of NEW SCIENTIST reflects some of the aspects of that work," Specific articles on coal, fuel cells, nuclear power.

Glaser, Peter E.
Beyond nuclear power—the larger-scale use of solar energy. Transactions of the New York Academy of Sciences, v. 31, Dec. 1969: 951–967.
"The following discussion of the future use of solar energy does not predict; it defines an alternative to guide the planning of future power-generating capacity so we will not deteriorate the quality of our 'spaceship' earth."
References, p. 966–967.

Graham, Frank, Jr.
Tempest in a nuclear teapot. Audubon, v. 72, Mar. 1970: 12–19.

Horton, Jack K.
Nuclear power—promise or problem? Edison Electric Institute bulletin, v. 37, June–July 1969: 207–212.
"The opportunities available to the United States from nuclear power—from the economic, the environmental and natural resource standpoints—suggest that more promises than problems are evident in our nuclear future."

Jensen, Albert C.
Fish and power plants. Conservationist, v. 24, Dec.–Jan. 1969–1970: 2–6.
"The Storm King Mountain pumped-storage project generated intense controversy and a study of the fish life near Cornwall-on-the Hudson. Here are the results."

Luce, Charles F.
Power for tomorrow: the siting dilemma. Record of the Association of the Bar of the City of New York, v. 25, Jan. 1970: 13–26.
Considers the dilemma between protection of the environment and location of electric power plants in the New York City metropolitan area, the present law, and possible improvements.

Lyle, Royster, Jr.
The Marble Valley Controversy. National parks magazine, v. 43, Nov. 1969: 14–17.
"Proposed pumped storage plant and reservoirs on Virginia's Calfpasture River meet opposition from local residents and conservationists."
McHale, John.
World energy resources in the futrue. Futures, v. 1, Sept. 1968: 4–13.
Main, Jeremy.
A peak load of trouble for the utilities. Fortune, v. 80, Nov. 1969: 116–119, 194, 196, 200, 205.
"The lights may go out while a sluggish industry struggles with management failures, construction delays, and growing public resistance to new plants and transmission lines."
Millsap, Ralph H.
Nuclear energy's environmental advantages. Edison Electric Institute bulletin, v. 37, Oct. 1969: 333–336.
A New river. Environment, v. 12, Jan.–Feb. 1970: 36–40.
"The nuclear power plants now planned for the shores of the Great Lakes will discharge heated water equal to the volume of flow of the Mississippi River at its mouth."
Novick, Sheldon.
Earthquake at Giza. Environment, v. 12, Jan.–Feb. 1970: 2–15.
"The atomic burial grounds at the Hanford Reservation are the most costly tombs since the days of the pharoahs—and hold as much radioactivity as would be released in a nuclear war."
[Nuclear power plans for New Hampshire; a symposium.] Forest notes, no. 100, fall 1969: 2–10.
A forum consisting of 4 articles by authors with different viewpoints on nuclear power plans for New Hampshire.
Contents: Electric power and the environment, by W. C. Tallman.—Nuclear reactors, a threat to the environment, by J. W. Parker.—The need for effective regulations, by R. P. Shapiro.—Reasonable doubt should be resolved, by Raymond Brighton.
Pace, Clark.
When built-in growth strikes back. Exchange, v. 30, Oct. 1969: 6–13.
"Everybody is using more power, and the utilities, suffering under an embarrassment of riches, symbolized by blackouts and threats of blackouts, can't build plants fast enough."
Palisades PWR Power Station—a special survey. Nuclear engineering international, v. 15, Jan. 1970: 27–42.
Partial contents.—Palisades PWR nuclear power station, by K. Swarts.—Sitework & plant construction, by J. Lescoe.—Steam and power conversion system, by K. Swarts.
Phillips, James G.
Electric power problems. [Washington] Editorial Research Reports, 1969. 939–956 p. (Editorial research reports, Dec. 17, 1969, v. 2, no. 23).
Reichle, Leonard F. C.
Nuclear power—1970–80. Public utilities fortnightly, v. 85, Feb. 12, 1970: 36–43.
"The author predicts that nuclear stations soon will be the predominant type of power producer among larger-size units during the 1970's."
Seaborg, Glenn T.
Environment . . . and what to do about it; part II. American forecasts, v. 75, Oct. 1969: 22–23, 54–56.
The chairman of the U.S. Atomic Energy Commission attempts to clear up some of the misunderstanding and apprehension a large segment of the public shares over the safety of nuclear plants, and reviews ". . . a few ways in which nuclear technologies are contributing to our understanding of the environment and allowing us to improve our relationship to it."
Seaborg, Glenn T.
Looking ahead in nuclear power. Edison Electric Institute bulletin, v. 37, June–July 1969: 188–195, 231.
Author speaks ". . . in defense of nuclear power and in support of the conservation of our natural resources and the improvement of our environment."

Seaborg, Glenn T.
The nuclear plant and our energy needs. Public utilities fortnightly, v. 85, Feb. 12, 1970: 19–26.
"The chairman of the Atomic Energy Commission discusses nuclear power and some of the problems that have concerned both the public and industry."

U.S. Federal Power Commission. Bureau of Power.
A review of Consolidated Edison Company 1969 power supply problems and ten-year expansion plans. [Washington] 1969. 89 p.

Wicklein, John.
Where will you be when the lights go out—again? Washington monthly, v. 1, Sept. 1969: 8–22.
"Since the Northeast Blackout of November, 1965, there have been 37 major, cascading power failures across the country." Discusses what ought to be done, including reliability proposals before Congress.